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Installation Energy Systems Selection Criteria

Fuels Selection Alternatives for Army Facilities

by
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This report provides background data for future revisions of Army documents pertaining to facilities fuels selection. Fuel price and availability forecasts are made for the years 1985 through 2009 for a variety of fuels, and costs are estimated for a number of combustion technologies, with emphasis on heating plants larger than 10 MBtu/hr. A life-cycle cost analysis procedure is described which integrates the fuel forecasts and the technology alternatives. The analysis procedure is used to rank the fuel alternatives in order of lowest total life-cycle cost. The rankings are relatively insensitive to the assumptions used in the analysis, and are seen to indicate a number of trends. The results consist of recommendations, based on these trends, which are grouped as general fuels selection criteria and criteria for solid fuels (such as coal), gas/oil fuels, and electricity.

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EXECUTIVE SUMMARY

The Army spends well over $1 billion each year for facilities energy. The extent of price increases (in constant dollars) since 1970 of oil, gas, coal, and electricity cannot be ignored. Since supplies of oil and gas are limited, additional increases in fuel prices may be expected in the future. This report studies the characteristics of current and developing energy technologies and compares the costs of various fuels, with the objective of providing information for developing a fuels selection strategy for Army installations.

The major goal of this report is to provide background data for future revisions of Army documents pertaining to facilities fuels selection. Results of this study are based on regional forecasts of fuels price and availability and on life-cycle cost analyses employing a variety of combustion technologies.

The information will be useful to several types of installation personnel. Boiler operators will obtain information about various types of boilers available as well as the use of alternative fuels. Managers will obtain an overview of a way to compare boiler costs. For example, how does the cost of a new "high-tech" boiler compare with that of a more common one, in which the initial cost is higher, but the fuel cost is lower, and what will be its effect on operation and maintenance costs?

Chapters 2 through 4 describe a variety of combustion technology alternatives (see Table 1) as well as several different boilers that use various fuels at a range of capacities. The objective in compiling this information was to obtain a variety of examples of fuel-burning options in order to determine the most cost-effective fuel for a given application. The technologies are not limited to the current Army inventory, but rather represent a wider range of alternatives. For example, the largest boilers described are designed for 650 psi, although Army boilers commonly operate below 200 psi.

Chapter 5 provides cost estimates for a variety of furnaces of the type that might be found in smaller applications such as family housing. The furnaces are fueled by gas, oil, coal, or electricity. Except for coal, the systems described for each fuel are widely used by the Army.

The discussion of fuels forecasting provided in Chapter 6 is oriented mainly toward managers who want a broad, but highly technical, overview of the fuels situation. A set of national and regional study projections is developed that represent the best estimate of the most likely fuel prices at any given time; however, they do not reflect possible fuel disruptions or their impacts. If long-term trends were to continue without disruptions, prices would be expected to follow the projections. Thus, the projections show a general trend, but prices would be expected to be sometimes above and sometimes below the stated figures.

Chapter 7 provides comparisons for example boiler alternatives and Chapter 8 describes a number of fuel selection criteria. These criteria generally follow the dictates of both common sense and current policy. The fuels selection rankings are essentially the same across a variety of databases obtained from both government and private sources.

Table I

Summary of Technology Alternatives

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Output Capacity Range (MBtu/hr) Minimum	Thermal Efficiency	Life (yr)	Capital Cost Coefficients A (10^3 \$/yr)	Capital Cost Coefficients B	O&M Variable A (10^3 \$/yr)	O&M Variable B	O&M Nonvariable A (10^3 \$/yr)	O&M Nonvariable B
1	Field erected stoker baghouse	Coal	500.00	50.00	0.81	40	672.0	0.60	0.444	1.00	42.1	0.60
2	Field erected stoker scrubber	Coal	500.00	50.00	0.79	40	753.0	0.61	3.26	1.00	54.9	0.60
3	Pulverized coal boiler baghouse	Coal	500.00	50.00	0.85	40	714.0	0.61	0.754	1.00	46.9	0.60
4	Pulverized coal boiler scrubber	Coal	500.00	50.00	0.83	40	787.0	0.62	3.57	1.00	59.6	0.60
5	Field erected AFBC baghouse	Coal	500.00	50.00	0.81	40	794.0	0.60	3.18	1.00	51.3	0.60
6	Field erected wood stoker	Wood	500.00	50.00	0.76	25	937.0	0.57	0.556	1.00	44.3	0.60
7	Field erected waste stoker	Waste	500.00	35.00	0.65	20	2448.0	0.53	3.85	1.00	91.2	0.60
8	Field erected DRDF stoker	DRDF	500.00	50.00	0.79	25	1062.0	0.57	0.932	1.00	52.5	0.60
23	Coal circulating fluid bed	Coal	500.00	50.00	0.80	25	473.0	0.70	3.18	1.00	51.3	0.60
24	Wood circulating fluid bed	Wood	500.00	50.00	0.75	25	510.0	0.70	1.16	1.00	50.3	0.60
25	Waste circulating fluid bed	Waste (RDF)	500.00	50.00	0.59	20	903.0	0.70	3.95	1.00	99.6	0.60
26	DRDF circulating fluid bed	DRDF	500.00	50.00	0.77	25	544.0	0.70	1.23	1.00	60.8	0.60
52	Packaged coal stoker	Coal	50.00	10.00	0.75	25	349.5	0.59	21.0	0.48	155.0	0.44
9	Packaged coal stoker baghouse	Coal	50.00	10.00	0.75	25	389.0	0.59	28.8	0.48	163.0	0.44
10	Packaged coal firetube	Coal	20.00	5.00	0.75	20	351.0	0.53	21.0	0.48	155.0	0.44
53	Packaged coal firetube baghouse	Coal	20.00	5.00	0.75	20	397.0	0.53	28.8	0.48	163.0	0.44
11	Packaged wood stoker	Wood	50.00	10.00	0.71	25	514.0	0.55	27.8	0.46	163.0	0.44
12	Packaged waste stoker	Waste	35.00	7.00	0.63	20	870.0	0.53	42.8	0.59	202.0	0.43
13	Packaged DRDF stoker	DRDF	50.00	10.00	0.73	25	549.0	0.56	29.6	0.51	180.0	0.44
14	Packaged coal AFBC	Coal	70.00	3.00	0.75	25	353.0	0.62	28.8	0.48	163.0	0.44
15	Packaged wood AFBC	Wood	50.00	5.00	0.71	25	521.0	0.55	27.8	0.46	163.0	0.44
16	Packaged waste AFBC	Waste (RDF)	50.00	5.00	0.63	20	880.0	0.53	42.8	0.59	202.0	0.43
17	Packaged DRDF AFBC	DRDF	50.00	5.00	0.73	25	557.0	0.56	29.6	0.51	180.0	0.44
18	Heat recovery incinerator	Waste	40.00	2.00	0.50	15	639.0	0.54	299.0	0.55	28.5	0.45
22	Pressurized fluid bed	Coal	200.00	30.00	0.83	25	807.0	0.53	3.31	1.00	48.6	0.60
32	Coal reconversion baghouse	Coal	500.00	50.00	0.81	15	438.0	0.55	0.444	1.00	42.1	0.60
33	Coal reconversion scrubber	Coal	500.00	50.00	0.79	15	483.0	0.59	3.26	1.00	54.9	0.60
34	Coal-wood retrofit	Wood	50.00	12.00	0.68	15	62.0	0.52	27.8	0.46	163.0	0.44
35	Coal-DRDF retrofit	DRDF	50.00	12.00	0.71	15	326.0	0.43	29.6	0.51	180.0	0.44
36	Coal-waste retrofit	Waste	50.00	12.00	0.61	15	730.0	0.44	42.8	0.59	202.0	0.43
19	Field erected gas/oil	Gas/oil	500.00	50.00	0.82	50	256.0	0.64	0.243	1.00	24.7	0.60
20	Packaged gas/oil fire tube	Gas/oil	25.00	5.00	0.80	25	108.0	0.50	4.61	0.80	158.0	0.31
21	Packaged gas/oil water tube	Gas/oil	150.00	25.00	0.80	40	103.0	0.63	18.8	0.38	129.0	0.34
27	Small low-Btu gasification	Coal	50.00	5.00	0.60	25	461.0	0.55	11.9	0.69	217.0	0.40
28	Large low-Btu gasification	Coal	500.00	40.00	0.62	25	951.0	0.60	3.76	1.00	88.4	0.60
29	Medium-Btu gasification	Coal	500.00	40.00	0.62	25	1316.0	0.58	3.79	1.00	92.0	0.60
30	Wood low-Btu gasification	Wood	50.00	5.00	0.55	25	592.0	0.53	10.2	0.69	217.0	0.40
31	Waste low-Btu gasification	Waste	50.00	5.00	0.49	20	1040.0	0.53	33.8	0.69	270.0	0.40
37	Coal-oil mix retrofit	COM	350.00	20.00	0.79	15	181.0	0.60	0.218	1.00	29.2	0.60
38	Coal-oil retrofit scrubber	COM	350.00	20.00	0.77	15	234.0	0.62	1.63	1.00	37.0	0.60
39	Coal-water mix retrofit	CWM	350.00	20.00	0.78	15	242.0	0.64	0.446	1.00	34.3	0.60
40	Coal-water retrofit scrubber	CWM	350.00	20.00	0.76	15	328.0	0.65	3.33	1.00	46.9	0.60
41	Gas furnace	Gas	0.50	0.04	0.75	25	8.3	0.62	0.0	1.00	0.02	0.00
42	Gas high-efficiency furnace	Gas	0.10	0.02	0.92	15	7.64	0.40	0.0	1.00	0.05	0.00
43	Oil furnace	Oil	0.50	0.04	0.75	25	9.0	0.62	0.0	1.00	0.04	0.00
44	Oil high-efficiency furnace	Oil	0.50	0.04	0.90	15	15.3	0.62	0.0	1.00	0.12	0.00
46	Electric resistance furnace	Electricity	0.25	0.01	1.00	25	3.9	0.50	0.0	1.00	0.02	0.00
47	Heat pump	Electricity	0.54	0.024	1.80	25	94.3	0.90	0.0	1.00	1.18	0.50
45	Coal furnace	Coal	0.50	0.04	0.65	25	32.2	0.69	0.0	1.00	7.30	0.66

General Criteria

For new construction, the fuel selected, as well as the design of heating units or plants, should be based on an economic study of the life-cycle costs of the technology alternatives and heating requirements to be served, using a 25-year analysis period. For units or plants of more than 20 million Btu/hr (MBtu/hr) output, the fuel, operation, and maintenance costs should be based on an annual capacity use of 60 percent over the 25-year analysis period. (The annual capacity use represents the annual energy output as a fraction of the potential annual output.)

As new or developing technologies such as high-efficiency furnaces become available and nearly competitive economically, consideration should be given to establishing Army demonstration projects for these technologies.

There may be cases where it is cost-effective for a plant to use several primary fuels.

Criteria for Coal and Other Solid Fuels

Solid fuels include solid fossil fuels such as coal, biomass fuels such as wood, and solid waste fuels. Coal is the most important of these because of favorable forecasts of coal prices and availability. Solid waste fuels include refuse-derived fuel and densified refuse-derived fuel.

New units or plants of 100 MBtu/hr output or more should generally have coal as the primary fuel. Both conventional and fluidized-bed technologies may be considered and compared for technical and economic feasibility. All units or plants constructed to burn solid fuel should include those auxiliaries necessary to meet air pollution criteria.

Where technically and economically feasible, the use of combustion technologies that burn waste or biomass may be considered in the design of new facilities.

Criteria for Gas/Oil Fuels

New single-fuel gas or oil units or plants of 20 MBtu/hr output or more should be discouraged. Where new units or plants of 20 MBtu/hr output or above are being designed for oil or gas, dual-fuel gas/oil units capable of operation on both gas and oil, if both are available, should be considered. Dual-fuel burners are marketed that use both natural gas and distillate oil. Alternatively, it may be economically better to use separate replacement burner systems for natural gas and for residual oil.

Existing single-fuel oil-burning units or plants of more than 20 MBtu/hr output should be provided with the dual-fuel capability of also burning natural gas, where available, to provide increased flexibility in response to fluctuations in the prices and availability of either fuel.

Existing single-fuel natural gas units or plants of more than 20 MBtu/hr output should be modified to provide dual-fuel capability, where feasible, to provide increased flexibility in response to fluctuations in fuel prices and availabilities. Possible alternative fuels include residual oil and coal-slurry fuels.

New oil-fired units might be permitted to use distillate fuel oil (No. 2) for sizes up to 5 MBtu/hr output capacity. Those of 20 MBtu/hr output capacity or more should be able to burn a variety of grades of heavier oil, No. 4 through No. 6.

Existing distillate oil units or plants of more than 5 MBtu/hr output should be modified to reduce use of this fuel. Distillate may be used in units where the annual capacity use is less than 20 percent because of the difficulties involved in storing and burning No. 6 oil.

Criteria for Electricity

The use of electrical resistance heating of large plants is generally not recommended.

Electrical resistance heating of smaller units or plants should be considered only where economically justified in comparison with other energy technologies, and where permitted by current policy guidance.

Implementation

In implementing these recommendations, current policy must be followed in fuels selection for the Army, with Army Regulation 420-49 being the principal policy document for guidance; however, for site-specific fuels selection guidance, Engineer Technical Letter 1110-3-332 must be followed.

FOREWORD

This work was conducted for the Office of the Assistant Chief of Engineers (OACE) under Project 4A162781AT45, "Energy and Energy Conservation"; Task Area C, "Energy Systems/Fuels"; Work Unit 004, "Installation Energy Systems Selection Criteria." The work was performed by the Energy Systems Division (ES), U.S. Army Construction Engineering Research Laboratory (USA-CERL). The OCE Technical Monitor was Mr. B. S. Wasserman, DAEN-ZCF-U.

Appreciation is expressed to Mr. R. W. Gilmer of the Tennessee Valley Authority for helpful discussions of fuels price and availability, and to Mr. B. Salimi of USA-CERL-ES for his contribution in implementing the technology cost equations.

Dr. G. R. Williamson is Chief of USA-CERL-ES. COL Norman C. Hintz is Commander and Director of USA-CERL, and Dr. L. R. Shaffer is Technical Director.

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FUELS SELECTION ALTERNATIVES FOR ARMY FACILITIES

1 INTRODUCTION

Background

The energy consumed in Army facilities operations costs well over $1 billion each year, and represents 84 percent of total Army energy expenditures. Since 1970, the prices of oil and gas have nearly quadrupled (in constant dollars), while those of coal and electricity have nearly doubled. Since further increases in fuel prices are expected, a fuel selection strategy is required that considers both current and emerging energy technologies, as well as projections of future fuel availability and costs. For the Army, the central document to embody this strategy is Army Regulation (AR) 420-49.[1] This document determines what fuels can be considered for a particular heating energy application. Although dated subsequent to the OPEC price increases of 1973-74, the AR does not reflect more recent events. Hence, the Army needs background information that will influence future revisions of the AR and other policy documents pertaining to fuels selection.

A previous study by the U.S. Army Construction Engineering Research Laboratory (USA-CERL)[2] described and provided cost estimates for various fuel-burning technologies. The information obtained in that research is used in developing the fuels selection strategies proposed in the current study.

Objective

The objective of this study is to develop a recommended fuels selection strategy for Army installations.

Approach

Three tasks were necessary to develop a fuels selection strategy:

1. Develop price and availability forecasts for a variety of fuels

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[1] Army Regulation 420-49, *Heating, Energy Selection, and Fuel Storage, Distribution, and Dispensing Systems* (Department of the Army, November 1976). Pending revision of the AR, current policy is transmitted in a letter from the Office of the Chief of Engineers (OCE) (DAEN-ZCF-U), 11 July 1984, Subject: General Planning/Design Criteria--Energy Source Selection and Application Criteria for Defense Facilities. For site-specific fuels selection guidance, Engineer Technical Letter 1110-3 332 must be followed.

[2] E. T. Pierce, et al., *Fuel-Burning Technology Alternatives for the Army*, Interim Report E-85/04/ADA151527 (U. S. Army Construction Engineering Research Laboratory [USA-CERL], 1985).

2. Gather data on alternative combustion technologies that will employ the variety of fuels at various capacities

3. Develop and apply a life-cycle cost analysis ranking procedure that integrates the fuels forecasts and technology alternatives.

The analysis procedure was then used to rank the fuel alternatives in order of lowest total life-cycle cost. It was applied over a range of plant capacities and use factors to develop recommended facilities fuels selection criteria.

Mode of Technology Transfer

It is recommended that the information in this report be used as background data for future revisions to the Army's fuel selection policies through AR 420-49, *Heating, Energy Selection, and Fuel Storage, Distribution and Dispensing Systems.*

2 TECHNOLOGY OVERVIEW

Technical descriptions and cost estimates were developed for about 50 combustion technologies. The objective was to obtain a variety of examples of fuel-burning options in order to determine the most cost-effective fuel for a given application. Hence, the technologies are not limited to the current Army inventory, but are intended to represent a wider range of alternatives that use a number of fuels and supply a variety of output capacities. For example, the largest boilers described in this report are designed for 650 psi,* although Army boilers commonly operate below 200 psi.

Summary Table

To provide an easy reference to these combustion technologies, Table 1 summarizes some of the important parameters. (The technology numbers used in USA-CERL Interim Report E-85/04 are retained for reference.) The columns in the table labeled "technology," "fuel type," "output capacity range," and "thermal efficiency" represent the type of parameters studied for each technology. For example, Technology 4, "pulverized coal boiler scrubber," uses a "low-cost" coal and includes a baghouse as well as a scrubber. It is field-erected and usually large (200 to 500 MBtu/hr output). The output capacity range** maximum and minimum limits are guidelines for using the cost equations developed for this study. Sizes outside this range may be available, although less common. The column labeled "life" refers to the life used here for a technology, which is highly dependent on the funds available for maintenance. The specification of economic life and O&M funding have been coordinated in this report.

Six columns of Table 1 are devoted to cost equation coefficients.*** Capital cost and operation and maintenance (O&M) cost equations are described in the *Cost Estimation* section below.

A number of references were consulted for technical insight and other information about the technologies in Table 1. Although individual cost estimates seemed accurate in many of the sources, the intent was to attain consistency across the technologies in this analysis, and thus those estimates may not always agree closely with the results reported here.

Elements Common Among Technologies

Many pieces of equipment and certain O&M practices are common among different technologies. These were identified to avoid repetition in the equipment and O&M descriptions provided for the individual technologies.

*Metric conversion factors are provided on p 139.

**Except when noted otherwise, capacities are given in MBtu/hr of output energy. (M stands for mega.)

***The general form of the equations is AX^B, where the coefficients are A and B.

Table 1

Summary of Technology Alternatives

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Output Capacity Range (MBtu/hr) Minimum	Thermal Efficiency	Life (yr)	Capital Cost Coefficients A (10^3 \$/yr)	Capital Cost Coefficients B	O&M Cost Coefficients Variable A (10^3 \$/yr)	O&M Cost Coefficients Variable B	O&M Cost Coefficients Nonvariable A (10^3 \$/yr)	O&M Cost Coefficients Nonvariable B
1	Field-erected stoker baghouse	Coal	500.00	50.00	0.81	40	672.0	0.60	0.444	1.00	42.1	0.60
2	Field-erected stoker scrubber	Coal	500.00	50.00	0.79	40	753.0	0.61	3.26	1.00	54.9	0.60
3	Pulverized coal boiler baghouse	Coal	500.00	50.00	0.85	40	714.0	0.61	0.754	1.00	46.9	0.60
4	Pulverized coal boiler scrubber	Coal	500.00	50.00	0.83	40	787.0	0.62	3.57	1.00	59.6	0.60
5	Field-erected AFBC baghouse	Coal	500.00	50.00	0.81	40	794.0	0.60	3.18	1.00	51.3	0.60
6	Field-erected wood stoker	Wood	500.00	50.00	0.76	25	937.0	0.57	0.556	1.00	44.3	0.60
7	Field-erected waste stoker	Waste	500.00	35.00	0.65	20	2448.0	0.53	3.85	1.00	91.2	0.60
8	Field-erected DRDF stoker	DRDF	500.00	50.00	0.79	25	1062.0	0.57	0.932	1.00	52.5	0.60
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24	Wood circulating fluid bed	Wood	500.00	50.00	0.75	25	510.0	0.70	1.16	1.00	50.3	0.60
25	Waste circulating fluid bed	Waste (RDF)	500.00	50.00	0.59	20	903.0	0.70	3.95	1.00	99.6	0.60
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18	Heat recovery incinerator	Waste	40.00	2.00	0.50	15	639.0	0.54	299.0	0.55	28.5	0.45
22	Pressurized fluid bed	Coal	200.00	30.00	0.83	25	807.0	0.53	3.31	1.00	48.6	0.60
32	Coal reconversion baghouse	Coal	500.00	50.00	0.81	15	438.0	0.55	0.444	1.00	42.1	0.60
33	Coal reconversion scrubber	Coal	500.00	50.00	0.79	15	483.0	0.59	3.26	1.00	54.9	0.60
34	Coal-wood retrofit	Wood	50.00	12.00	0.68	15	62.0	0.52	27.8	0.46	163.0	0.44
35	Coal-DRDF retrofit	DRDF	50.00	12.00	0.71	15	326.0	0.43	29.6	0.51	180.0	0.44
36	Coal-waste retrofit	Waste	50.00	12.00	0.61	15	730.0	0.44	42.8	0.59	202.0	0.43
19	Field-erected gas/oil	Gas/oil	500.00	50.00	0.82	50	258.0	0.64	0.243	1.00	24.7	0.60
20	Packaged gas/oil fire tube	Gas/oil	25.00	5.00	0.80	25	108.0	0.50	4.61	0.80	158.0	0.31
21	Packaged gas/oil water tube	Gas/oil	150.00	25.00	0.80	40	103.0	0.63	18.8	0.38	129.0	0.34
27	Small low-Btu gasification	Coal	50.00	5.00	0.60	25	461.0	0.55	11.9	0.69	217.0	0.40
28	Large low-Btu gasification	Coal	500.00	40.00	0.52	25	951.0	0.60	3.76	1.00	88.4	0.60
29	Medium-Btu gasification	Coal	500.00	40.00	0.62	25	1316.0	0.58	3.79	1.00	92.0	0.60
30	Wood low-Btu gasification	Wood	50.00	5.00	0.55	25	592.0	0.53	10.2	0.69	217.0	0.40
31	Waste low-Btu gasification	Waste	50.00	5.00	0.49	20	1040.0	0.53	33.8	0.69	270.0	0.40
37	Coal-oil mix retrofit	COM	350.00	20.00	0.79	15	181.0	0.60	0.218	1.00	29.2	0.60
38	Coal-oil retrofit scrubber	COM	350.00	20.00	0.77	15	234.0	0.62	1.63	1.00	37.0	0.60
39	Coal-water mix retrofit	CWM	350.00	20.00	0.78	15	242.0	0.64	0.446	1.00	34.3	0.60
40	Coal-water retrofit scrubber	CWM	350.00	20.00	0.76	15	328.0	0.65	3.33	1.00	46.9	0.60
41	Gas furnace	Gas	0.50	0.04	0.75	25	8.3	0.62	0.0	1.00	0.02	0.00
42	Gas high-efficiency furnace	Gas	0.10	0.02	0.92	15	7.64	0.40	0.0	1.00	0.05	0.00
43	Oil furnace	Oil	0.50	0.04	0.75	25	9.0	0.62	0.0	1.00	0.04	0.00
44	Oil high-efficiency furnace	Oil	0.50	0.04	0.90	15	15.3	0.62	0.0	1.00	0.12	0.00
46	Electric resistance furnace	Electricity	0.25	0.01	1.00	25	3.9	0.50	0.0	1.00	0.02	0.00
47	Heat pump	Electricity	0.54	0.024	1.80	25	94.3	0.90	0.0	1.00	1.18	0.50
45	Coal furnace	Coal	0.50	0.04	0.65	25	32.2	0.69	0.0	1.00	7.30	0.63

Boiler House or Buildings

All boilers and gasifiers are assumed to require a building. Buildings are also required for the waste incinerator technologies. These buildings are assumed to be insulated steel structures that enclose the boiler or gasifier plant. They contain an employee washroom, an office area, lighting, ventilation, ladders, and gratings.

Coal- and Wood-Handling Systems

The fuel handling for packaged or small systems (less than 50 MBtu/hr) is assumed to include a truck unloading facility with an undertruck hopper and crushers or hammer mills to size the fuel, a 10-day-capacity storage site with a bucket elevator or belt conveyor, and a 24-hr capacity overhead feed bunker. For large, field-erected energy systems, equipment for wood or coal handling includes a railroad-car-unloading underground hopper with conveyors leading to a 30-day storage pile and 3-day silo. Fuel is sized properly by crushers or hammer mills, and belt conveyors take it to an 8-hr storage bunker for feeding.

Waste and DRDF Handling System

For any size waste system, handling includes truck unloading into an enclosed building with negative-draft ventilation; air is pulled from the building into the boiler to eliminate fugitive fumes and odors. Storage silos and conveyors are airtight. A 10-day silo storage is assumed for all sizes, since 30-day storage would be impractical. DRDF handling systems are similar to those for wood or coal but have covered conveyors, watertight silos, and covered storage piles. This lowers dust levels and keeps moisture out of the DRDF to avoid handling difficulties and possible sanitation problems.

Ash-Handling Systems

All solid fuel technologies and coal/oil mixture (COM) and coal/water mixture (CWM) retrofit technologies include a costly ash-handling system. This system consists of an ash hopper under the boiler (or gasifier) which discharges ash intermittently into a clinker grinder and then onto a pneumatic conveyor for transport to a storage silo. The pneumatic conveyor also transports flyash from the baghouse to the ash silo. This silo has an ash capacity for slightly more than 1 day of firing at full load and is equipped with truck-loading equipment for ash disposal.

Fuel Oil Feed System

For packaged oil-fired boilers, the feed system includes a 7-day storage tank with a transfer pump and piping to bring fuel oil to the boiler, two feed pumps (one spare) with full firing capabilities, and a fuel heating system if the fuel is No. 6 oil. For field-erected boilers, a 30-day-capacity carbon steel cone roof tank is used for storage. This tank is equipped with an oil heater and a circulating pump. All No. 6 fuel lines are steam-traced.[1]

[1]Foster Wheeler Development Corp., *Industrial Steam Supply System Characteristics Program Phase I, Conventional Boilers and AFBC*, FWDC #9-41-8903 (Oak Ridge National Laboratory [ORNL], August 1981).

Boiler

Boilers are made up of (1) the combustion chamber, (2) all firing equipment such as stokers and burners, (3) boiling and superheater tubes and economizers (or firetubes), and (4) all air intake equipment such as air heaters, fans, and ducts. The boiler includes any necessary foundation and supports, fans, and ducting for the air system, controls, and burners. In each case, the boiler's cost reflects the design features needed to accommodate the fuel being fired. For instance, with coal firing, the boilers are designed to handle the ash, flame length, and erosivity of flue gas. When possible, each of these aspects is considered and reflected in the cost. For some technologies, such as fluidized bed combustion, these have less effect.

Boiler Feedwater Treatment

A feedwater system includes equipment for softening makeup water and adding chemicals, a deaerator, and feedwater pumps and piping.

Cost-Related Factors

Direct Costs

"Direct costs" cover all expenditures for equipment, land, installation, and construction.

Indirect Costs

Indirect costs cover engineering, field expenses, insurance, contractor fees, working capital, and shakedown and performance tests. For all technologies considered, this was assumed to be 30 percent of the direct costs.

Contingency Costs

Contingency costs are added to the total capital expense to account for unknowns such as construction problems, unforeseen equipment needs, modifications, and delays. A contingency of 20 percent was added to the total direct and indirect costs for most estimates.

Labor Costs

The total annual labor costs for most technologies include supervision, direct labor, and maintenance labor. Maintenance labor was often assumed to be contracted and therefore was reported as subcontract labor. Labor costs were divided into specific categories when reliable information was available. In some cases, labor and supervision were combined and categorized as "manpower," and maintenance labor and replacement parts (materials) may have been lumped together.

For many technologies with labor requirements, manpower was assumed to be available for continuous operation. Furthermore, the labor expenses were assumed to be fixed O&M costs (no variation with capacity factor). The only exception was for waste incinerators, which are often intended to operate only on certain workshifts.

Ash Disposal Costs

Ash disposal costs were assumed to be about \$15/ton for a coal boiler with a 25-MBtu/hr output capacity. These costs were assumed to decrease on a dollar-per-ton basis with increased output capacity for packaged boilers. For field-erected boilers, a disposal cost of about \$7/ton was used.

Cost Estimation

The American Association of Cost Engineers defines five levels of cost estimates: order of magnitude, study, preliminary, definitive, and detailed. These levels are distinguished by how much detail and accuracy are contained in each.[4] Most costs presented in this report would be considered study estimates, indicating an uncertainty of about 20 percent. Some technologies such as pressurized fluidized bed combustion (PFBC) have not yet been built for commercial use, so estimates for these systems are necessarily less accurate.

Much effort has been made to keep all cost estimates consistent to allow meaningful comparisons. For example, all cost estimates, except for retrofit technologies, are based on a "greenfield site." A "greenfield site" usually refers to a new or vacant site, or one with no similar energy system. For this study, "greenfield site" means there is no existing equipment or construction to remove or to reduce capital expenditures and that no personnel, services, or supplies can be shared to reduce annual O&M costs.

It was recognized that simple equations were needed to relate costs to boiler size. Normally, a cost savings per unit output is realized as the size increases. Equipment capital costs are thus affected by the equipment's size in what is called an "economy of scale." For example, a pump twice as large as another will cost less than twice as much because, per unit of output, it is generally cheaper to make large equipment. This relationship can be expressed as a power function of the output capacity.

For simplicity and accuracy, equations were developed to give capital investment and annual O&M costs for each technology based on this relationship. The general form is AX^B, where the coefficient A is the equipment cost (10^3 1980 dollars) at the base size X (thermal output capacity in MBtu/hr). The exponent B is called a "scaling factor" and is usually less than one. An example of this for a pump is: cost = $600\ X^{0.6}$, where X is the pump size in gallons per unit time, and cost is in dollars. This is a common method of expressing costs for technologies that have a large range of sizes, and such equations can be put into a standard form convenient for computer use.

Nonfuel O&M costs are affected not only by the plant size but also by components that vary with the length of operation. In general, variable costs include chemicals, limestone, electricity, and ash disposal; fixed costs are for items such as labor associated with O&M. The general form of the variable cost equation is similar to that for capital cost: AX^B (CF), where CF is the capacity factor. "Capacity factor" is defined as the actual annual output divided by the output had the plant operated at maximum capacity

[4] J. R. Canada and J. A. White, Jr., *Capital Investment Decision Analysis for Management and Engineering* (Prentice-Hall, 1980), p 203.

for the entire year. In this study, some technologies were assumed to have no variable O&M costs.

Scaling factors had to be estimated to develop cost equations. For many of the technologies (e.g., boilers and gasifiers), scaling factors were available for the individual pieces of equipment comprising the technology.[5] These factors were used consistently throughout the study when applicable. For all technologies, cost estimates were obtained or formulated for different sized units and costs were then correlated to find the overall scaling factors. Cost estimates in this report are for sizes typical of the technology and near the middle of the size range being considered.

[5]Foster Wheeler, August 1981; PEDCo Environmental, Inc., *Cost Equations for Industrial Boilers* (U. S. Environmental Protection Agency [USEPA], Economic Analysis Branch, January 1980).

3 SOLID FUEL BOILERS

Several technologies burn solid fuels such as coal, wood, waste, and densified refuse-derived fuel (DRDF). Table 2 summarizes these solid-fuel technologies. (The technology numbers are the same as in Table 1.)

Field-Erected Solid-Fuel Boilers

Field-erected solid fuel boilers include pulverized-coal-fired, stoker-fired, and fluidized-bed technologies (Technologies 1 through 8 in Table 2). The reference design in the following discussion is for a large unit producing 250 MBtu/hr of output steam. As a starting point, the stoker-fired and pulverized-coal-fired boilers are based partly on estimates of conceptual plant designs, engineering characteristics, and operating requirements developed by the Foster Wheeler Corporation.[6] In addition, several cost estimates from other sources were reviewed, and industrial users of solid fuel boiler systems were contacted to obtain information about costs actually incurred.[7]

This information has been integrated to make cost estimates that are as consistent and credible as possible. Costs reflect the characteristics of the fuel fired, such as ash content, melting points, and heating value (Table 3). In addition, fuel properties affect the costs of fuel and ash-handling systems. For example, coal pulverizer costs depend on the coal's heating value and grindability. Compared with Foster Wheeler's estimates, the cost of site work has been increased for this study; costs for mobile solids handling equipment (e.g., trucks), fire protection, and feedwater treatment have been decreased, and costs have been added for electrical equipment (e.g., transformers).

Coal-Fired Boilers

The pulverized-coal boiler (Technologies 3 and 4 in Table 2) uses natural circulation with a fin tube waterwall. The typical design has a nominal heat output of 250 MBtu/hr (heat absorbed in the boiler), and is described in Table 4. The pulverizer is a ball-mill type, with two units in operation and one spare. Four intervane coal burners with forced draft front air control registers are provided with four oil guns for burning No. 6 oil during startup. The design fuel is Eastern high-sulfur bituminous coal. The unit has forced-draft, induced-draft, primary air, and sealing air fans. The furnace is equipped with eight retractable steam soot blowers: four in the superheater section and two each in the boiler bank tubes and economizer.

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[6] Foster Wheeler, August 1981.

[7] O. H. Klepper, et al., *A Comparative Assessment of Industrial Boiler Options Relative to Air Emission Regulations*, ORNL/TM-8144 (ORNL, July 1983); PEDCo Environmental, Inc., *The Population and Characteristics of Industrial/Commercial Boilers*, EPA-600/7-79-178a (USEPA, May 1979); United Engineers and Constructors, *Costs of Small Coal Burning Systems Producing Steam and Hot Water*, UE&C-UCC-770617 (ORNL, August 1977); *A Coal-Fired Steam Generating Plant for the Radford Army Ammunitions Plant* (United Engineers and Constructors, September 1976); S. C. Kurzius and R. W. Barnes, *Coal-Fired Boiler Costs for Industrial Applications*, ORNL/CON-67 (ORNL, April 1982); *Steam, Its Generation and Use*, rev., 38th ed. (Babcock & Wilcox, 1975).

Table 2

Summary of Solid Fuel Boilers

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Minimum
Field Erected Solid Fuel Boilers				
1	Field-erected stoker baghouse	Coal	500.00	50.00
2	Field-erected stoker scrubber	Coal	500.00	50.00
3	Pulverized coal boiler baghouse	Coal	500.00	50.00
4	Pulverized coal boiler scrubber	Coal	500.00	50.00
5	Field-erected AFBC baghouse	Coal	500.00	50.00
6	Field-erected wood stoker	Wood	500.00	50.00
7	Field-erected waste stoker	Waste	500.00	35.00
8	Field-erected DRDF stoker	DRDF	500.00	50.00
23	Coal circulating fluid bed	Coal	500.00	50.00
24	Wood circulating fluid bed	Wood	500.00	50.00
25	Waste circulating fluid bed	Waste (RDF)	500.00	50.00
26	DRDF circulating fluid bed	DRDF	500.00	50.00
Packaged Solid Fuel Boilers				
52	Packaged coal stoker	Coal	50.00	10.00
9	Packaged coal stoker baghouse	Coal	50.00	10.00
10	Packaged coal firetube	Coal	20.00	5.00
53	Packaged coal firetube baghouse	Coal	20.00	5.00
11	Packaged wood stoker	Wood	50.00	10.00
12	Packaged waste stoker	Waste	35.00	7.00
13	Packaged DRDF stoker	DRDF	50.00	10.00
14	Packaged coal AFBC	Coal	70.00	3.00
15	Packaged wood AFBC	Wood	50.00	5.00
16	Packaged waste AFBC	Waste (RDF)	50.00	5.00
17	Packaged DRDF AFBC	DRDF	50.00	5.00
18	Heat-recovery incinerator	Waste	40.00	2.00
22	Pressurized fluid bed	Coal	200.00	30.00
Retrofit Technologies				
32	Coal reconversion baghouse	Coal	500.00	50.00
33	Coal reconversion scrubber	Coal	500.00	50.00
34	Coal-wood retrofit	Wood	50.00	12.00
35	Coal-DRDF retrofit	DRDF	50.00	12.00
36	Coal-waste retrofit	Waste	50.00	12.00

Table 3

Fuel Design Characteristics*

	Higher Heating Value (Btu/lb)	Ash Content (% by wt)	Moisture Content (% by wt)	Density (lb/cu ft)
Coal	11,800	10.6	9	85
Waste	4,500	30.0	40	40
DRDF	7,000	12.0	15	40
Wood**	4,500	1.3***	50	50
COM+	15,150	5.4	4	
CWM++	8,210	7.4	36	
No. 6 oil	18,400	<0.5		

*All properties are on an "as received" basis.

**Wood is assumed to be green and from whole trees.

***Represents unburned residue after combustion rather than the mineral matter content which is 0.4 percent.

+Approximately 50 percent by weight #6 oil and 50 percent by weight bituminous coal and some additives.

++Seventy percent "as received" bituminous coal slurried with 30 percent water.

Table 4

Pulverized Coal Boiler Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	212.0
Pressure (psi)	650.0
Temperature, steam superheater outlet (°F)	750.0
Excess air (%)	20.0
Fuel-fired (10^3 lb/hr)	24.5
Heat losses (%):	
Dry gas	7.18
Hydrogen and moisture in fuel	4.84
Moisture in air	0.17
Unburned combustibles	0.70
Radiation	0.36
Unaccounted and manufacturer's margin	1.50
Total losses (%)	15.0
Efficiency	85.0

The stoker boiler (Technologies 1 and 2 in Table 2) is a spreader design from Foster Wheeler.[8] It is also a nominal 250 MBtu/hr natural circulation steam generator with a welded fin tube waterwall. A continuous ash-discharge traveling grate of about 17 by 20 ft is fed by four spreader feeders. The boiler has a pneumatic flyash reinjection system. Table 5 gives typical design data.

For all field-erected coal boiler systems, coal is sized to be 5 x 0 in. (i.e., no pieces exceed 5 in.) as received by rail cars carrying about 100 tons each. The cars are unloaded into an underground hopper, and coal is conveyed at a rate of 300 tons/hr to either a dead-storage pile sized for 30 days' retention or to a 3-day storage silo. Oversized coal is crushed to 1-1/4 x 0 in. and then is conveyed at a rate of 100 tons/hr to an 8-hr storage bunker. When the coal in the 8-hr storage bunker is reduced to a 4-hr supply, the crusher is started and the bunker is refilled from the 3-day silo. This permits operation during weekends without material handling or equipment operators and provides a margin of 4 hr to call maintenance personnel who can correct minor problems that may occur in the crushing and refilling conveyor systems.

With this arrangement, replenishment of the 3-day storage bin requires hauling by front-end loaders from the coal pile to the rail car unloading hopper. The crusher can be fed directly from the coal pile by a front-end loader and conveyor. The 100 tons/hr crusher/conveyor system is sized to allow the 8-hr bin to be refilled, with additional time for minor repairs. For instance, during maximum demand on the 250 MBtu/hr boiler system, the crusher/conveyor will operate for 1 hr in an 8-hr period.

The car unloading, stockpiling, and silo-filling conveyors were sized for 300 tons/hr, which permits the unloading of three 100-ton cars per hour. This rate would allow 1800 tons to be unloaded in 6 hr, thus providing about 1300 tons/day for the stockpile during single-stoker boiler operation. The facility has a front-end loader.

Table 5

Coal Stoker Boiler Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	212.0
Pressure (psi)	650.0
Temperature, steam superheater outlet (°F)	750.0
Excess air (%)	28.0
Fuel fired (10^3 lb/hr)	25.6
Heat losses (%):	
Dry gas	7.18
Hydrogen and moisture in fuel	4.84
Moisture in air	0.17
Unburned combustibles	5.0
Radiation	0.36
Unaccounted and manufacturer's margin	1.50
Total losses (%)	19.0
Efficiency (%)	81.0

[8] Foster Wheeler, August 1981.

Bottom ash from the stoker and pulverized coal units is collected in an ash hopper, from which it is discharged intermittently through a clinker grinder and conveyed pneumatically into a storage silo. The grinder can accommodate 30 tons/day, and the silo can store ash for 1 day. A contractor hauls the ash away.

The boiler stack is made of precast Gunite-lined concrete and is about 200 ft high. The stack is 7 ft in diameter and is designed for an exit flue temperature of 160°F. This lower limit is typical of conditions that would exist with the flue gas leaving a wet scrubber. However, higher temperatures present fewer corrosion problems.

The boiler building is about 100 by 140 by 88 ft, with a 30- by 100-ft single-story, concrete block building for support facilities. The building is designed to meet the applicable building codes.

The boiler feedwater (BFW) system is designed for 50 percent makeup. The BFW source is city water, with a demineralization system consisting of anion and cation resin beds to remove the dissolved solids. Bed regeneration uses sulfuric acid to replace cations (calcium and magnesium); caustic is used to replace anions (e.g., sulfate, chloride, and nitrate). Spent acid and caustic enter a neutralizing tank and are mixed before adding trim acid or caustic to adjust the pH before discharge. Oxygen is removed by steam stripping in the deaerator's tray section. A chemical oxygen scavenger (hydralazine) is added to the deaerator's base (drum section) to reduce oxygen to a very low level, thereby minimizing corrosion in the boiler. Phosphates (e.g., trisodium phosphate) are added to the boiler drum to suspend solids and prevent their deposition on heated surfaces.

Two boiler feedwater pumps are required: one is electrically driven and the other has a steam drive. Each is sized for full capacity (540 gal/min). Other auxiliary equipment includes a blowdown flash drum and heat exchanger, condensate storage tank, feedwater storage tank, and a fire protection system; each system includes the proper connective piping. No cost allowance is made for the steam distribution system. A wastewater treatment system treats water from rain runoff, boiler blowdown, and sanitary waste. This system consists of a holding pond, pumps, neutralizing tank, and connection to a municipal sewer.

Atmospheric Fluidized Bed Combustion (AFBC) seems to be an attractive alternative for industrial boilers, although it has several drawbacks. This technology has undergone a long, frustrating development period with limited success. However, it now appears that the private sector is working with this technology, and there is reason to believe it may become a commercial success. At least eight companies are marketing fluidized-bed systems.

In general, AFBC suffers from the same basic problem as other solid fuel systems. That is, heat release limitations mandate that systems larger than 50 MBtu/hr must be field-erected. Moreover, AFBC requires the same auxiliary and support facilities as any solid fuel system.

Foster Wheeler Development Corporation also did a detailed design and cost estimate of an AFBC system.[9] This system is based on Foster Wheeler's industrial fluidized-bed system and is similar to a unit in operation at Georgetown University.

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[9]Foster Wheeler, August 1981.

The typical design has a nominal heat output of 250 MBtu/hr; Table 6 gives other data. This system is a natural circulation boiler consisting of two fluidized-bed cells separated by a water wall. The fuel is Eastern high-sulfur bituminous coal. Air is supplied by a forced-draft fan, and the bed is controlled through two dampers in the air plenum. Air is ducted to two separate plenums and through a distribution plate.

Coal is fed overbed by mechanical spreader feeders. The spreader system is a unique feature that offers simple feeding and a less expensive boiler; however, both sulfur capture and carbon burnup may be less with this design than with an underfeed system. Limestone is also injected overbed through a simple feed point in each bed. A conventional superheater surface is located above the bed. A mechanical dust collector positioned downstream collects elutriated material, which is then reinjected into the bed. The bed material is drained into a fluidized-bed cooler that discharges its fluidizing air into the boiler convection area for heat recovery. The bottom material passes through an ash cooler to a silo sized to provide 1-day storage.

The coal-handling system is similar to that described for the conventional stoker-fired boiler. Limestone is unloaded from trucks and fed pneumatically to a 7-day storage silo. It is then conveyed pneumatically to an overhead hopper from which it is fed by gravity to the AFBC boiler. This bunker is on a scale to monitor the flow. The other auxiliary systems, (e.g., feedwater treatment, mobile solids handling, buildings, and stack) are similar to those for conventional boilers.

Table 6

Atmospheric Fluidized-Bed Boiler (AFBC) Design Conditions

Parameter	Condition
Steam produced (10^3 lb/hr)	213.0
Pressure (psi)	650.0
Temperature, steam superheater outlet ($^{\circ}$F)	750.0
Excess air (%)	22.0
Fuel fired (10^3 lb/hr)	25.7
Heat losses (%):	
Dry gas	4.84
Hydrogen and moisture in fuel and limestone	4.77
Moisture in air	0.05
Unburned combustibles	8.0
Radiation	0.40
Net solids loss	0.08
Unaccounted and manufacturer's margin	1.50
Forced-draft fan credit	-0.048
Total losses (%)	19.0
Efficiency (%)	81.0
Calcium-to-sulfur ratio (Ca/S)	2.9
Bed operating temperature ($^{\circ}$F)	1600
Fluidizing velocity (ft/sec)	8.0

Tables 7 and 8 give costs for field-erected coal-fired systems (the costs, scope of supply, and indirect costs were developed as described above). Table 9 shows an example use for scaling factors. A 250-MBtu/hr boiler costs \$18.6 million before adding in pollution control, and a 125-MBtu/hr boiler costs \$12.5 million. The degree of pollution control required for the smaller boiler may vary, depending on applicable regulations.

Wood, Waste, and DRDF Stoker Boilers

Wood, waste, and DRDF field-erected stoker boiler plants (Technologies 6 through 8 in Table 2)[10] have capabilities nearly identical to the coal-fired stoker plant described above. The costs and design of the boiler and much of the peripheral equipment will vary from those for Foster Wheeler's coal-fired spreader-stoker boiler plant due to differences in fuel properties (Table 3).

Table 10 gives an itemized list of capital investment requirements for 250-MBtu/hr output capacity wood-, waste-, and DRDF-fired spreader-stoker boiler plants.

Boiler size and design are determined mainly by the fuel properties expected. The waste-fired boiler is the most expensive because of the fuel's low heating value, poor combustion, high ash content and slagging potential, and erosion and fouling problems. The boiler must be about 50 percent larger than a coal-fired boiler and special materials are required for certain tube banks and other parts.[11] These same considerations apply to the DRDF boiler but to a lesser extent. A wood-fired stoker boiler has a slightly different design than one for coal firing, but the size and cost are nearly the same.[12]

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[10]PEDCo Environmental, Inc., 1979; PEDCo Environmental, Inc.,January 1980; United Engineers and Constructors, 1977.

[11]P. J. Karnoski and B. E. Byington, "Refuse Power Technology and Economics," presented at the American Power Conference, Chicago, IL (April 23, 1980); *Materials and Energy From Municipal Waste*, Vol 1, U. S. Congress, Lib. of Congress No. 79 600118 (Office of Technology Assessment, July 1979), pp 121-125; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, "Co-Firing Coal and Refuse-Derived Fuel in a Utility Steam Generator: Operational Experience and Corrosion Probe Evaluation," presented at American Power Conference, Chicago, IL (April 21-23, 1980); W. H. Pollock, "Supplementing Coal with Solid Waste Fuels," presented at the American Power Conference, Chicago, IL (April 21-23, 1980); J. E. Christian, *Resource Recovery for Institutions: A Technical, Environmental and Economic Feasibility Analysis for the Oak Ridge National Laboratory*, M. S. Thesis (University of Tennessee--Knoxville, (March 1980); H. I. Hollander, "Combustion Factors for Utilizing Refuse-Derived Fuels in Existing Boilers," presented at the Fourth National Conference, Energy and the Environment, Cincinnati, OH (October 4-7, 1976); Resource Planning Associates, Inc., *European Waste-to-Energy Systems, An Overview*, EC-77-C-01-2103 (Energy Research and Development Administration, June 1977); Resource Planning Associates, Inc., *European Waste-to Energy Systems: Case Study of Landshut, West Germany* (U.S. Department of Energy [DOE], September 1978).

[12]Mittlehauser Corporation, *Technology and Costs of Energy and Fuels from Biomass Resources, Vol I* (ORNL, January 1981); Mittlehauser Corporation, *Technology and Costs of Energy and Fuels from Biomass Resources, Vol II* (ORNL, February 1981); *Energy Production from Wood Residue* (Radar Systems Inc., 1978).

The cost estimates for spreader-stoker equipment are based mainly on the weight and volume of fuel that must be fired. For example, wood firing takes about two to three times the weight and four to five times the volume of coal firing. Waste firing requires a more complex, costly grate design because of the waste's poor combustion and variability.

Boiler house costs for the wood and DRDF boiler plants are estimated to be identical to those of the coal plant. However, the structure housing the waste-fired boiler must be larger to accommodate the large equipment and great number of employees.

Fuel-handling equipment costs are based largely on the volume and weight of fuel that must be received, conveyed, and stored. Wood, waste, and DRDF handling systems require much larger conveyors and hoppers than is necessary for a coal system. Waste handling includes a special tipping building and airtight conveying and storage, which results in an extremely high handling cost compared with other fuels. The ash-handling systems were scaled according to the output weight of ash expected for each boiler, including both bottom- and flyash removal.

The contingency used for the waste boiler plant cost estimate was 40 percent of the direct and indirect costs compared to the 20 percent value used for the other boiler plants. This larger value brings the total plant cost in Table 10 into closer agreement with other sources.[13]

Table 7

Field-Erected Coal Boilers*

Capital Category	Scaling Factor	Spreader-Stoker	Pulverized Coal	AFBC
Site work	0.6	250,000	250,000	250,000
Boiler plant	0.68	4,480,000	5,452,000	6,120,000
Stoker/pulverizer	0.60	585,000	1,167,000	
Boiler house	0.5	700,000	700,000	700,000
Stack	0.6	208,000	208,000	208,000
Feedwater treatment	0.6	418,000	418,000	418,000
Coal and limestone handling	0.38	2,349,000	2,349,000	2,964,000
Ash handling	0.38	771,000	771,000	1,091,000
Wastewater	0.59	342,000	342,000	342,000
Electrical	0.8	167,000	167,000	167,000
Piping	0.8	75,000	75,000	75,000
Direct subtotal		10,345,000	11,889,000	12,335,000
Indirects (30% of total direct costs)		3,103,000	3,570,000	3,701,000
Contingency (20% of direct and indirect costs)		2,690,000	3,094,000	3,207,000
Subtotal		16,138,000	18,563,000	19,243,000
Particulate control		2,287,000	2,135,000	2,534,000
Fuel gas desulfurization		3,410,000	3,410,000	
Total capital		21,835,000	24,108,000	21,777,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars.

[13]Mittlehauser Corporation, January 1981; P. J. Karnoski and B. E. Byington, 1980; *Materials and Energy From Municipal Waste*, 1979.

Table 8

Field-Erected Coal Boilers—Operation and Maintenance*

Category	Stoker-Fired Boiler	Pulverized Coal	AFBC
Boiler			
Direct manpower	$613,000	658,000	760,000
Electricity	41,000+12,500 (CF)***	41,000+95,000 (CF)	41,000+39,000 (CF)
Sublabor**	459,000	549,000	543,000
Ash disposal	82,000 (CF)	77,000 (CF)	258,000 (CF)
Boiler total	1,113,000+94,500 (CF)	1,248,000+172,000 (CF)	1,344,000+297,000 (CF)
Particulate Control			
Manpower	6,000	6,000	3,000
Electricity	17,000 (CF)	17,000 (CF)	17,000 (CF)
Sublabor**	33,000	30,000	62,000
Particulate total	39,000+17,000 (CF)	36,000+17,000 (CF)	65,000+17,000 (CF)
Desulfurization Chemicals			
Limestone			482,000 (CF)
FGD System			
Manpower	350,000	350,000	
Electricity	125,000 (CF)	125,000 (CF)	
Water treatment	6,000 (CF)	6,000 (CF)	
Lime	223,000 (CF)	223,000 (CF)	
Sodium	43,000 (CF)	43,000 (CF)	
Waste disposal	307,000 (CF)	307,000 (CF)	
	350,000+704,000 (CF)	350,000+704,000 (CF)	

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.
**Subcontract labor and maintenance parts.
***CF = capacity factor = actual annual heat output/potential annual heat output.

Table 9

Example Use of Scaling Factors for Two Boilers*

Capital Category	One Boiler (250 MBtu/hr)	Scaling Factor	One Boiler (125 MBtu/hr)
Site work	250,000	0.6	164,900
Boiler plant	5,452,000	0.68	3,402,900
Stoker/pulverizer	1,167,000	0.60	769,900
Boiler house	700,000	0.5	495,000
Stack	208,000	0.6	137,200
Feedwater treatment	418,000	0.6	275,800
Coal and limestone handling	2,349,000	0.38	1,805,100
Ash handling	771,000	0.38	592,500
Wastewater	342,000	0.59	227,200
Electrical	167,000	0.8	95,900
Piping	75,000	0.8	43,100
Subtotal	11,889,000		8,009,500
Indirects (30% of total direct costs)	3,570,000		2,402,800
Contingency (20% of direct and indirect costs)	3,094,000		2,082,500
Subtotal	18,563,000		12,494,800
Particulate control	2,135,000		
Fuel gas desulfurization	3,410,000		(depends on state or local regulations)
Total	24,108,000		

*In 1980 dollars.

Table 10

Field-Erected Stoker Boilers for Wood, Waste, or DRDF*

Category	Scaling Factor	Wood-Fired	Waste-Fired	DRDF-Fired
Site work	0.6	250,000	291,000	250,000
Boiler plant	0.68	4,480,000	7,840,000	5,600,000
Spreader stoker	0.68	1,154,000	1,378,000	855,000
Boiler house	0.38	700,000	816,000	700,000
Stack	0.59	208,000	208,000	208,000
Feedwater treatment	0.59	418,000	418,000	418,000
Fuel handling	0.38	4,198,000	10,094,000**	4,637,000
Ash handling	0.38	506,000	1,847,000	999,000
Wastewater treatment	0.58	342,000	513,000	398,000
Electrical	0.8	167,000	292,000	206,000
Piping	0.8	75,000	131,000	93,000
Total direct costs		12,498,000	23,828,000	14,364,000
Indirects (30% of direct costs)		3,749,000	7,148,000	4,309,000
Contingency (20% of direct and indirect costs)		3,249,000	12,390,000***	3,735,000
Particulate control (includes associated indirect costs and contingency)	0.85	2,287,000	2,287,000	2,287,000
Total		21,783,000	45,653,000	24,695,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars. Compiled from the following sources: PEDCo Environmental, Inc., 1979; United Engineers and Constructors, 1977; PEDCo Environmental, Inc., 1980; Mittlehauser Corporation, *Technology and Costs of Energy and Fuels from Biomass Resources, Vol I* (ORNL, January 1981); Mittlehauser Corporation, *Technology and Costs of Energy and Fuels from Biomass Resources, Vol II* (ORNL, February 1981); P. J. Karnoski and B. E. Byington, 1980; *Materials and Energy From Municipal Waste*, 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; *Energy Production from Wood Residue* (Rader Systems, Inc., 1978); H. I. Hollander, 1976; Resource Planning Associates, Inc., 1977; Resource Planning Associates, Inc., 1978).

**Includes airtight storage, conveying system, and a tipping building with negative draft ventilation.

***Forty percent contingency is used to increase cost to closer agreement with the following sources: Mittlehauser Corp., January 1981; P. J. Karnoski and B. E. Byington, 1980; *Materials and Energy from Municipal Waste*.

Table 11 gives annual O&M costs for 250-MBtu/hr output, wood, waste, and DRDF stoker boiler plants. O&M costs for the wood-fired plant are very similar to those estimated for the coal-fired plant (Table 8). However, the waste- and DRDF-fired stoker boiler plants have higher O&M cost estimates. This is attributed mostly to higher direct labor costs for operating these more complex plants and to the higher-cost subcontract labor and parts; these expenses are needed for more frequent and extensive repairs. Ash disposal costs are also very high for the waste-fired boilers.

Circulating Fluidized-Bed Combustion

The concept of fast or circulating fluidized-bed combustion (FBC) (Technologies 23 through 26 in Table 2) originated at about the same time as that of the more common dense fluidized bed. Circulating FBC has a higher superficial gas velocity than the dense phase. A more descriptive term is "entrained flow" because the particles are all generally entrained in the gas stream rather than simply agitated as in the bubbling bed.[14] The chief advantage with circulating FBC is the simple feed system. Also, for an industrial size unit, only one coal feed point is needed. In comparison, a dense bed requires several feed points, which means the system must have flow splitters or separate feed systems. Furthermore, the turndown ability is better with a circulating system.

Several companies are trying to market circulating fluidized-bed boilers, although only two systems are known to have been built in the United States. One of these, a 50,000-lb/hr unit designed for Gulf Oil Exploration, was chosen for the cost estimate in this study. This system consists of a waterwall combustion chamber, a hot cyclone, and a conventional convection heat-recovery system. This design is very similar to a conventional waterwall coal-fired boiler.

A hot cyclone collector separates entrained particles from the flue gas stream. The collected particles are then gravity fed to a lower chamber, where they are

Table 11

Field-Erected Stoker Boilers for Wood, Waste, or DRDF--Operation and Maintenance*

Category	Wood-Fired		Waste-Fired		DRDF-Fired	
Direct labor and supervision	645,800		1,137,800		711,400	
Electricity	41,000+95,000	(CF)	82,000+124,000	(CF)	41,000+54,000	(CF)
Subcontract labor and replacement parts	491,800		1,246,600		649,200	
Ash disposal	27,400	(CF)	821,000	(CF)	162,000	(CF)
Particulate removal	39,000+17,000	(CF)	39,000+17,000	(CF)	39,000+17,000	(CF)
Total	1,218,000+139,000	(CF)	2,505,000+962,000	(CF)	1,441,000+233,000	(CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

[14] L. Green, "Distributed Power Generation by Burning Coal-Cleaning Waste," 10th Energy Technology Conference, Washington, DC (February 1983).

elutriated through a nonmechanical seal for return to the combustion chamber. The seal is a dip leg similar to a "J" trap in a sanitary drain pipe. This is also the coal feed point.

Flue gas exits the cyclone collector and continues to the convection zone, imparting heat to the boiler bank and economizer. From the convection zone, the flue gas moves to a dust collection system that removes the entrained particles. The gas is then discharged to the stack by an induced-draft fan.

Primary and secondary fans supply combustion air. Primary air is supplied below the air distribution grid at the bottom of the combustion chamber. Secondary air is supplied to various spots in the combustion chamber and also is ducted to the startup burners. A rotary positive displacement blower applies high-pressure air to the non-mechanical seal below the cyclone collector. This air is used to fluidize solids captured by the hot cyclone and return them to the lower combustion chamber. Feedwater is supplied to the economizer, in which it is heated before delivery to the steam drum. From the drum, the water is delivered through downcomers to the combustion chamber waterwalls and is returned as a steam/water mixture to the steam drum. Because of erosion problems, there are no in-bed tubes. Depending on the type of fuel and steam conditions, a convective boiler bank section may als be required to complete evaporation not provided for by combustion chamber waterwalls. All evaporative sections are arranged for natural circulation. Air preheat and steam superheat sections may also be required, depending on the specific application.

Coal typically is conveyed to a separate surge hopper adjacent to the boiler. From this hopper, feed systems under automatic control feed the coal to the boiler. Limestone is fed directly to the boiler from a main storage hopper.

Bottom ash from the combustion chamber is removed from the lower part of the chamber through a special valve that classifies the fines for reinjection into the combustion chamber. Conventional soot blowing cleans the boiler surfaces. This process is confined mainly to the boiler's convection zone.

Pyropower offers units of this type from 50,000 Btu/hr to 400 MBtu/hr. This company supplied cost quotes at both ends of the size range as well as cost estimates for using the system to burn wood and waste. These costs were used to develop Tables 12 and 13. The estimates account for the variation needed in boiler design to accommodate the different fuels. Fuel feed and auxiliary system costs are similar to those for other technologies using the same fuel.

Packaged Solid-Fuel-Fired Boilers

Coal-Fired Watertube Stoker Boilers

There are three major types of packaged, watertube stoker boilers (Technology 9 or 52, Table 2) available which differ mainly by the firing method: underfeed, overfeed, and spreader stokers. An underfeed stoker operates by pushing coal from below up onto a sloping retort and over combustion grates (tuyeres) where air is introduced from underneath. Ash is pushed off the far ends of the grates. An overfeed stoker uses a moving or chain grate that picks up a layer of coal and moves slowly into the combustion

Table 12

Circulating Bed AFBC Boilers for Coal, Wood, Waste, or DRDF*

Capital Category	Coal	Wood	Waste	DRDF
Site work	250,000	250,000	291,000	250,000
Boiler plant	6,763,000	7,260,000	7,800,000	7,260,000
Boiler house	700,000	700,000	816,000	700,000
Stack	208,000	208,000	208,000	208,000
Feedwater treatment	418,000	418,000	418,000	418,000
Coal/limestone/ wood handling	2,814,000	4,198,000	10,094,000	4,637,000
Ash handling	1,091,000	506,000	1,847,000	999,000
Wastewater	342,000	342,000	513,000	398,000
Electrical	167,000	167,000	292,000	206,000
Piping	75,000	75,000	131,000	93,000
Subtotal	12,828,000	14,124,000	22,410,000	15,169,000
Indirects (30% of total direct costs)	3,848,000	4,237,000	6,723,000	4,551,000
Contingency (20% of total direct and indirect costs)	3,335,000	3,672,000	11,653,000**	3,944,000
Subtotal	20,011,000	22,033,000	40,786,000	23,644,000
Particulate control (indirects and contingency included)	2,534,000	2,300,000	2,300,000	2,300,000
Total	22,545,000	24,333,000	43,086,000	25,964,000

*Capital cost estimates, 250 MBtu/hr heat output capacity, 1980 dollars. "DRDF" is densified refuse-derived fuel.

**A 40 percent contingency is used to arrive at a realistic cost estimate.

Table 13

Circulating Bed AFBC Boilers for Coal, Wood, Waste, or DRDF—Operation and Maintenance*

Category	Coal	Wood	Waste	DRDF
Direct labor and supervision	760,000	760,000	1,285,000	858,000
Electricity	41,000+39,000 (CF)	41,000+95,000 (CF)	82,000+124,000 (CF)	41,000+54,000 (CF)
Subcontract labor and replacement parts	542,000	542,000	1,329,000	732,000
Ash disposal	258,000 (CF)	27,000 (CF)	821,000 (CF)	162,000 (CF)
Particulate removal	65,000+17,000 (CF)	39,000+17,000 (CF)	39,000+17,000 (CF)	39,000+17,000 (CF)
Limestone or bed materials	482,000 (CF)	150,000 (CF)	25,000 (CF)	75,000 (CF)
Total	1,408,000+796,000 (CF)	1,382,000+289,000 (CF)	2,735,000+987,000 (CF)	1,670,000+308,000 (CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

zone. Ash is dumped off the opposite end of the grate. Both underfeed and overfeed (chain grate) stokers are mass burning and, for purposes of this study, are identical. A spreader stoker uses an overhead rotating spreader mechanism to distribute a thin layer of coal over a traveling or chain grate. Some fines burn in suspension as the coal falls to the grate.

Most packaged stokers used today are the mass burning type (e.g., moving grate, vibrating grate, and push rod.)[15]. This type of stoker was used to develop cost equations for a size range of 10 to 50 MBtu/hr output steam capacity. Although the larger units are available, a more typical size for this technology would be closer to 10 MBtu/hr. The approximate size limit for packaged stoker boilers shipped by rail is 50 MBtu/hr. The lower limit (10 MBtu/hr) represents the lower size that allows confidence in the cost equations. Stoker units smaller than 1.5 MBtu/hr have been reported. Since the different stoker feed mechanisms have a relatively small effect on plant costs, the equations developed for the underfeed stoker are also reasonable approximations of the costs associated with overfeed or spreader stokers.

Tables 14 and 15 give costs for a 25-MBtu/hr output underfeed stoker coal boiler, along with costs for waste, wood, and DRDF stokers of the same capacity. Chapter 2 gives the assumptions used for the important equipment and O&M cost categories. Most of these costs are derived from two sources,[16] with some modifications. The scaling factors used for each piece of equipment are included to show how the final capital investment equations were derived.

The firetube coal-fired boiler (Technology 10, Table 2) has been available in the United States for a number of years. An example is included here for comparison with the watertube technology. This technology is more common in Europe and is typically smaller (5 to 20 MBtu/hr). The boiler system consists of a packaged firetube boiler with a top feed stoker (screw fed from above). The boiler is skid-mounted and rail-shipped to the site. The reference costs in Table 16 are for a three-pass scotch marine type boiler with a wet back and are from recent vendor estimates. The remaining cost categories were estimated consistent with the estimates for the watertube packaged systems described previously. Table 16 shows the reference capital cost estimates. The nonfuel O&M costs are assumed to be similar for the packaged coal-fired watertube system of similar size (Table 15).

Packaged Wood, Waste, and DRDF Stoker Boilers

The assumptions for cost estimating in the underfeed, watertube coal stoker boiler were used to develop costs for wood, waste, and DRDF stoker boilers (Technologies 11 through 13 in Table 2). An underfeed stoker mechanism probably is not suitable for these fuels, so it is assumed that a moving grate stoker (either overfeed or spreader) mechanism can be substituted without major changes in boiler plant costs. The size limit for packaged wood and DRDF boilers would be about 50 MBtu/hr output capacity with truck shipment (20 tons/truck--same as coal), but the waste stoker would have a reduced maximum capacity.[17]

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[15]PEDCo Environmental, Inc., 1979.

[16]PEDCo Environmental, Inc., January 1980; PEDCo Environmental, Inc., *Capital and Operating Costs of Particle Controls on Coal- and Oil-Fired Industrial Boilers*, EPA-450/5-80-009 (USEPA, August 1980).

[17]PEDCo Environmental, Inc., August 1980; Rader Systems, Inc., 1978; H. I. Hollander, 1976.

Table 14

Packaged Stoker Watertube Boilers for Coal, Waste, DRDF, or Wood*

Item	Scaling Factor	Coal	Waste	DRDF	Wood
Boiler	0.7	571,400	752,800	628,400	571,400
Boiler house	0.5	167,600	197,100	177,200	167,600
Stack	0.6	5,300	5,300	5,300	5,300
Water treatment	0.6	53,900	53,900	53,900	53,900
Solid fuel handling and storage	0.4	426,000	1,362,000	780,600	796,200
Ash handling	0.4	167,700	400,900	217,200	120,500
Electrical	0.8	35,800	49,500	40,000	35,800
Piping	0.8	48,200	66,700	53,900	48,200
Other	0.8	7,000	10,500	8,100	7,000
Total direct cost		1,482,900	2,898,700	1,964,600	1,805,900
Indirects (30% of directs)		444,900	869,600	589,400	541,800
Baghouse (includes indirects)		220,000	220,000	220,000	166,800
Total directs and indirects		2,147,800	3,988,300	2,774,000	2,514,500
Contingency (20% of directs and indirects)		429,600	797,700	554,800	502,900
Total		2,577,400	4,786,000	3,328,800	3,017,400

*Capital cost estimates, 25 MBtu/hr heat capacity, 1980 dollars. Compiled from the following sources: PEDCo Environmental Inc., 1979; United Engineers and Constructors, 1977; PEDCo Environmental, Inc., 1980; PEDCo Environmental, Inc., January 1980; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; P. J. Karnoski and B. E. Byington, 1980; *Materials and Energy From Municipal Waste*, July 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; Rader Systems Inc., 1978; H. I. Hollander, 1976; W. J. Boegly, Jr., *Solid Waste Utilization—Incineration with Heat Recovery*, ANL/CES/TE 78-3, Contract W-31-109-Eng-38 (DOE, April 1978).

Table 15

Packaged Stoker Boilers or Packaged AFBC for Coal, Waste, DRDF, or Wood—Operation and Maintenance*

Item	Boiler Operating at an Annual 60% Plant Capacity Factor			
	Coal	Waste	DRDF	Wood
Direct labor (fixed)	308,800	308,800	308,000	308,000
Supervision (fixed)	103,100	103,100	103,100	103,100
Maintenance labor (fixed)	96,400	162,000	129,200	96,400
Replacement parts (fixed)	105,600	177,500	141,500	105,600
Electricity (60% variable)	47,900	47,900	47,900	47,900
Process water (variable)	600	600	600	600
Ash disposal (variable)	11,800	104,300	22,500	4,100
Chemicals (variable)	2,700	2,700	2,700	2,700
Baghouse (fixed)	35,000	35,000	35,000	35,000
Baghouse (variable)	36,400	36,400	36,400	36,400
Total	748,300	978,300	827,700	740,600

*Annual nonfuel operation and maintenance costs, 25 MBtu/hr heat output capacity, 1980 dollars.

Table 16

Packaged Coal Firetube Boilers*

Item	Factor	20 MBtu/hr	10 MBtu/hr
Boiler	0.5	280,000	189,000
Boiler house	0.5	150,000	106,000
Stack	0.6	5,000	5,000
Water treatment	0.6	47,000	31,000
Fuel handling and storage	0.4	390,000	295,000
Ash handling	0.4	153,000	116,000
Electrical	0.8	30,000	17,000
Piping	0.8	40,000	23,000
Other	0.8	6,000	3,000
Total direct		1,101,000	783,000
Indirect (30%)		330,000	235,000
Contingency (20%)		286,000	203,000
Total (without baghouse)		1,717,000	1,221,000
Baghouse		225,000	130,000
Total (with baghouse)		1,943,000	1,351,000

Cost equations: Cost = $351(X)^{0.53}$ Without baghouse
Cost = $397(X)^{0.53}$ With baghouse

*Capital cost estimates, two output capacities, 1980 dollars.

The cost items in Table 14 were developed by comparing equipment needed for each type of fuel to that required for coal-firing. The equipment size, design, and cost differences depend almost entirely on fuel property differences. For example, in comparing waste to coal, a waste combustion system requires several times the volume feed rate and a substantially greater ash disposal capability (by weight) versus a coal combustion system with the same output capacity. This results from differences in heating value, ash content, fuel density, and boiler efficiency for each fuel. Table 3 gives the assumptions made for the various fuels' properties.

Waste and DRDF have special requirements that affect the choice of fuel handling and storage equipment. Unlike coal and wood, which often can be left in open storage piles, waste and DRDF cannot be exposed to the weather. For waste, it is assumed that all storage silos, bins, conveyors, and feeders are enclosed and airtight. Furthermore, waste is delivered to a tipping building which is kept under a slight vacuum when possible by drawing the boiler combustion air from the tipping area. These special requirements are for sanitation, since waste can harbor dangerous bacteria and give off strong odors. However, such requirements increase the cost of the handling and storage systems.

To develop capital and O&M costs, it was estimated that a waste boiler would be about 50 percent larger than a coal boiler, whereas a DRDF boiler would be 15 percent larger and a wood boiler would be about the same size. The larger sizes for waste and DRDF are a result of their higher ash content, poor combustion qualities, and increased boiler fouling and corrosion. The boiler house for the waste-burning system was assumed to be 50 percent larger and the DRDF boiler house was assumed 15 percent larger than for the wood or coal boiler house.

The solid fuel handling systems were sized based on volume flow rate of each fuel. After using the scaling factors to find costs, the waste system cost was increased to account for airtight sealing and tipping. The DRDF system costs were increased by 10 percent for watertight covering of all equipment.

Ash disposal was assumed to cost about $15/ton. For large amounts of ash, such as the type generated by waste combustion, a cost savings may be realized on a per-ton basis. However, ash from waste combustion is probably less desirable for landfilling than coal ash. For this reason, $15/ton was used for each 25-MBtu/hr boiler, regardless of fuel.

Ash-handling equipment costs were calculated by scaling according to ash mass flowrate. About nine employees were included in estimating direct labor plus benefits and overhead expenses.[16] Supervision costs were also developed. It was assumed that subcontract labor would be used for certain maintenance and repair work. In addition to higher capital costs, maintenance for waste (and, to a lesser degree, DRDF) boilers costs more than for wood and coal boilers--a result of increased ash, corrosion, and complexity.

Atmospheric Fluidized-Bed Coal-Fired Boilers

Coal-fired packaged AFBC (Technology 14 in Table 2) is a developing technology, with the first commercial packaged boiler placed on-line in 1981 (designed by Johnston

[16]PEDCo Environmental, Inc., January 1980.

Boiler Company for a Central Soya plant).[19] The Great Lakes boiler (Combustion Engineering for the U.S. Department of Energy) was also designed as a packaged adaptation of the "A" configuration, but has not yet had additional U.S. sales. The Iowa Beef unit (Wormser Engineering) is designed to produce 70,000 lb of steam per hour, and includes cogeneration. It uses two beds in series inside a packaged combustion unit. The first (lower) bed is designated a "combustion bed," whereas the second (upper) bed is for sulfur capture. Other manufacturers also offer fluidized-bed burners, but these are mainly for fuels other than coal. The Johnston Boiler Company has sold about 30 of its packaged firetube coal-fired AFBC boiler, which was chosen as the reference design.

Because AFBC boilers are still an emerging technology, the amount of cost data available is limited.[20] However, the boiler itself is only one part of the steam plant. Equipment such as the boiler house, stack, and water treatment, coal delivery, storage, and feeding systems, will be very similar to the corresponding parts of a packaged stoker boiler.

The boiler design used to develop costs was a firetube model with fluidized-bed combustion chamber and above-bed screw-type coal feeders. Oil and gas can also be burned in the bed for either startup or full operation. The bed material is assumed to be sand, although limestone is an option when sulfur dioxide absorption is desired. Watertubes cool the bed walls and separate the bed into compartments (usually three) so that sections can be shut down for partial-load operation. Combustion products are cooled as they travel through firetubes inside the water chamber. The boiler can produce saturated steam at pressures up to 300 psig, although 150 psig is more typical.

Operating cost and capital investment estimates for a 25-MBtu/hr AFBC coal-fired boiler system are in Tables 15 and 17, respectively. Operating costs are assumed to be the same as those for a stoker boiler. Coal-fired stoker and AFBC boilers appear to be similar in size and complexity, and require nearly the same peripheral equipment. Based on discussions with industrial users, it appears that about the same number of operations and repairs and similar amounts of process water, electricity, and chemicals are needed for either a stoker or AFBC boiler when the unit is operated with sand, and sulfur dioxide capture is not attempted. AFBC requires sand for the bed materials and may require slightly more ash removal due to sand elutriation, but these costs were assumed negligible. It is apparent that the boiler house, stack, water treatment system, fuel and ash-handling equipment, and baghouse would be nearly identical for an AFBC or stoker packaged boiler. A comparison of Tables 14 and 17 reveals that the only capital cost differences determined were for sand handling and boiler costs (a slight difference). Chapter 2 describes most of the assumptions used for estimating costs.

Discussions with AFBC system users suggested two major trends: (1) when the unit is operated with above-bed coal feeding, the problems are similar to those of a spreader-stoker system and (2) when the unit is operated to control sulfur with limestone feed and in-bed coal injection, performance tends to be erratic and unreliable.

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[19] A. N. Vince and R. D. Barnhart, "Fluidized Bed Boiler, an Industrial Application at Central Soya Company, Inc., Marion, Ohio," *Proceedings, 20th Annual Kentucky Industrial Coal Conference*, University of Kentucky, Lexington, April 29, 1981 (Central Soya Company Inc., 1981); B. Vail, "Fluid-bed Unit Is First on Line Without Subsidy," *Energy User News* (September 14, 1981).

[20] A. N. Vince and R. D. Barnhart; B. Vail, "Fluid-Bed Unit Is First on Line Without Subsidy," *Energy User News* (September 14, 1981).

Table 17

Packaged AFBC Boilers for Coal, Waste, DRDF, or Wood*

Item	Scaling Factor	Coal	Waste	DRDF	Wood
Boiler	0.68	580,000	764,100	637,800	580,000
Boiler house	0.5	167,600	197,100	177,200	167,600
Stack	0.6	5,300	5,300	5,300	5,300
Water treatment	0.6	53,900	53,900	53,900	53,900
Solid fuel handling and storage	0.4	426,000	1,362,000	780,600	796,200
Sand handling	0.4	7,900	7,900	7,900	7,900
Ash handling	0.4	171,000	400,900	217,200	120,500
Electrical	0.8	35,800	49,500	40,000	35,800
Piping	0.8	48,200	66,700	53,900	48,200
Other	0.8	7,000	10,500	8,100	7,000
Total direct cost		1,502,700	2,917,900	1,931,900	1,822,400
Indirects (30% of directs)		450,800	875,400	594,600	546,700
Baghouse (includes indirects)		220,000	220,000	220,000	166,800
Directs and indirects		2,173,500	4,013,300	2,796,500	2,535,900
Contingency (20% of directs & indirects)		434,700	802,700	559,300	507,200
Total		2,608,200	4,816,000	3,355,800	3,043,100

*Capital cost estimates, 25 MBtu/hr heat output capacity, 1980 dollars. Compiled from the following sources: S. C. Kurzius and R. W. Barnes, April 1982; PEDCo Environmental, Inc., January 1980; PEDCo Environmental, Inc., August 1980; A. N. Vince and R. D. Barnhart, 1981; B. Vail, 1981; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; P. J. Karnoski and B. E. Byington, 1980; *Materials and Energy From Municipal Waste*, 1979; R. J. Petersdorf, S. M. Sansone, A. L. Plumley, W. R. Roczniah, and C. R. McGowin, 1980; W. H. Pollock, 1980; J. E. Christian, 1980; Rader Systems Inc., 1978; H. I. Hollander, 1976; W. J. Boegly, Jr., 1978.

Wood, Waste, and DRDF AFBC Boilers

Capital investment and annual O&M costs were developed for packaged wood-, waste-, and DRDF-fired AFBC boiler plants (Technologies 15 through 17 in Table 2) using previous assumptions and making comparisons with the packaged coal-fired AFBC boiler and wood-, waste-, and DRDF-fired stoker boiler cost estimates. The previous discussion, containing details and assumptions for wood-, waste-, and DRDF-fired stoker boilers also apply to the corresponding AFBC boilers.

Table 15 gives annual O&M costs for 25-MBtu/hr output packaged AFBC boilers, which are the same as for stoker units. No significant O&M cost differences between packaged stoker and AFBC units could be determined. This may result partly from the fact that little is known about O&M for AFBC boilers. However, much of the peripheral features such as the boiler house, stack, water treatment system, and fuel-handling, storage, and ash-handling equipment will be identical or very similar to that associated with stoker boilers. Therefore, the O&M and capital costs for such items will be about the same, regardless of boiler design. The packaged stoker and AFBC boiler units also may be of comparable size and complexity and therefore should have similar labor and maintenance costs.

Table 17 gives itemized capital cost breakdowns for 25-MBtu/hr boilers. The costs for most items are identical to those for stoker boilers firing the same fuel (Table 14), with the only differences in capital cost seen for the boiler itself[24] and the bed material

[24] A. N. Vince and R. D. Barnhart; B. Vail, 1981.

handling system (not part of stoker units). It should be noted that Table 2 describes the fuel for technologies 16 and 25 as "waste (RDF)". This indicates that some additional processing may be required before the waste can be used in AFBC boilers. This site-specific consideration has not been applied to the costs in Table 17.

Waste Incinerators With Heat Recovery

Several types of packaged waste incinerators are being marketed, including rotary kilns, mass burning, and other grate design variations.[22] The starved-air modular systems seemed the most attractive for use as the reference design in this study. A typical heat recovery waste incinerator (Technology 18) consists of a primary combustion chamber that operates at substoichiometric conditions, a secondary combustion chamber that uses excess air, and a heat-recovery boiler unit. Waste is fed into the primary chamber by a ram mechanism that pushes in a measured amount at certain intervals.

Supplemental oil or gas must be used to bring the combustion chambers to proper temperatures for startup and to complete combustion during shutdown.[23] It may also be necessary to use a certain amount of oil or gas at all times to sustain waste combustion and to achieve a reasonable efficiency. A typical amount of supplemental fuel required would have a heating value equal to 10 percent of the output steam. However, this value may vary greatly, depending on the waste properties and incinerator design.

Table 18 gives a capital investment cost breakdown. Included are a charging bin with a ram feeder and guillotine door, a supplemental fuel system, primary and secondary combustion chambers with a firetube heat-recovery boiler, fans, air ducts, and controls. Vehicles required are two dump trucks and a front-end loader. Vehicle tools, other maintenance tools, and equipment for cleaning and sanitation are also considered. The building includes a heavy-duty tipping floor (for heavy vehicles), ventilation, concrete platforms, a sprinkler system, fire equipment, and 2-day waste fuel storage bin capacity. Below the incinerator clean-out door is a concrete ash pit with water sprayers and a wet-ash conveyor that dumps into an ash bin.

Table 19 gives the annual O&M cost estimates for two sizes of incinerator units. Most of the cost is for direct labor, supervision, maintenance labor, and replacement parts. Most of these costs were considered to be variable rather than fixed, because waste incinerators are often intended for limited use.

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[22] S. A. Hathaway and J. P. Woodyard, *Technical Evaluation Study: Solid Waste As a Fuel at Ft. Bragg, NC*, Technical Report E-95/ADA034416 (USA-CERL, 1976); S. A. Hathaway, *Design Features of Package Incinerator Systems*, Technical Report E-106/ADA040743 (USA-CERL, 1977); S. A. Hathaway and R. J. Dealy, *Technology Evaluation of Army-Scale Waste-to-Energy Systems*, Technical Report E-110/ADA042579 (USA CERL, 1977); S. A. Hathaway, *Recovery of Energy From Solid Waste at Army Installations*, Technical Report E-118/ADA044814 (USA-CERL, 1977); A. N. Collishaw and S. A. Hathaway, *Technical Evaluation Study: Energy Recovery from Solid Waste at Fort Dix, NJ, and Nearby Civilian Communities*, Technical Report E-136/ADA062653 (USA-CERL, 1978); S. A. Hathaway, *Application of the Package Controlled-Air Heat-Recovery Solid Waste Incinerator on Army Fixed Facilities and Installations*, Technical Report E-151/ADA071539 (USA-CERL, 1979); W. J. Boegly, Jr., *Solid Waste Utilization—Incineration with Heat Recovery*, ANL/CESITE 78-3, Contract W-31-109-Eng-38 (DOE, April 1978).

[23] J. E. Christian, 1980.

Table 18

Waste Incinerator With Heat Recovery*

Item	Scaling Factor	Cost
Incinerator/boiler	0.6	350,000
Water treatment	0.6	15,100
Stack	0.6	1,500
Building	0.5	140,000
Vehicles and equipment	0.4	150,000
Waste handling	0.4	25,000
Piping	0.8	8,800
Electrical	0.8	6,600
Other	0.8	2,000
Subtotal	699,000	
Indirects (30% of direct costs)		209,700
Contingency (20% of direct and indirect cost)		181,700
Total		1,090,400

Capital cost equation capital investment = 639 $X^{0.5[illegible]}$, where cost is in 10^3 1980 dollars and X is in MBtu/hr output capacity.

*Capital cost estimate, 1200 lb/hr waste input, 2.7 MBtu/hr heat output, 1980 dollars. Compiled from: PEDCo Environmental, Inc., January 1980; J. E. Christian, 1980; W. J. Boegly, Jr., 1978.

Table 19

Waste Incinerator With Heat Recovery—Operation and Maintenance*

Item	Annual Cost: 2.7 MBtu/hr Output	Annual Cost: 11.25 MBtu/hr Output
Direct labor and supervision	29,600 + 372,400 (CF)	54,800 + 766,400 (CF)
Maintenance labor and replacement parts	15,000 + 130,000 (CF)	30,000 + 255,300 (CF)
Electricity	7,000 (CF)	29,000 (CF)
Water and sewer	1,500 (CF)	6,500 (CF)
Chemicals	2,000 (CF)	8,500 (CF)
Ash disposal	16,000 (CF)	64,000 (CF)
Total	44,600 + 528,900 (CF)	84,000 · 1,129,700 (CF)

2220 Btu/lb are recovered from the waste combustion.
O&M cost equation for 2- to 40-MBtu/hr plants operating with a plant capacity factor of 0.1 0.5:

$$O\&M = 299\ X^{[illegible]}\ (CF) + 28.5\ X^{[illegible]},$$

where cost is in 10^3 \$/yr, X is the output capacity in MBtu/hr, and CF is the plant capacity factor.

*Annual operation and maintenance costs, two output capacities, 1980 dollars. Compiled from: PEDCo Environmental, Inc., 1980; J. E. Christian, 1980; W. J. Boegly, Jr., 1978.

It may be desired to use a waste incinerator with heat recovery to supplement the steam system only for the day shift on weekdays. This would represent minimum planned use of the incinerator. It would be fired 8 or 9 hr/day about 250 days/yr (no firing on holidays). About 4 hr of work time must be allowed for startup, shutdown, and ash cleanout. For the 2.7-MBtu/hr unit, it was estimated that about 2.5 fulltime employees would be required, along with one-half of a supervisor's time. The capacity factor for this case would be estimated at about 0.20, assuming the 10 hr/day, 250 days/yr, and 70 percent availability, which includes both scheduled and unscheduled downtime. The large unit (11.25 MBtu/hr) would require about five employees and one supervisor for this same scenario. Increasing hours of operation requires more shift workers and possibly a shift supervisor. These assumptions were used for the O&M costs in Table 19.

The maintenance labor and replacement parts cost estimate covers incinerator equipment and vehicle maintenance. Maintenance repairs include patching the refractory coating, replacing thermocouples and door seals, motor upkeep, soot removal, cleaning, and sanitation.

Packaged Pressurized Fluidized-Bed Boilers

The packaged industrial pressurized fluidized-bed boiler described in this report (PFBC, Technology 22 in Table 2) exists in concept only. The design and cost estimates for the PFBC system are taken from an Oak Ridge National Laboratory study for the U. S. Department of Energy.[24]

The concept is based on the fact that one potential way to lower steam generator cost is to "package" the boiler. Packaging entails shop fabrication, assembly, and suitable sizing for rail shipment. Coal packaged boilers show savings of about 30 percent over comparably sized field-erected units. Further savings in operating expenses are likely because of the higher reliability of shop-fabricated units implied in tube weld failure data.[25] The largest conventional coal-fired boiler that can be packaged is about 50 MBtu/hr heat input because of railroad shipment constraints. Large physical sizes are necessary for conventional coal-fired systems to provide a large enough volume for radiant heat transfer and low gas velocities through the boiler (relative to oil and natural gas boilers).

The concept of coal-fired PFBC involves burning the fuel in a dense air suspension of limestone particles. The mass flow of air is fixed by the combustion requirements, and the air's superficial velocity is chosen according to fluidization mechanics. Pressurizing the air with an exhaust-gas-driven turbocharger increases its density and allows more of it to be input per unit volume. Since the combustion heat release is a strong function of the air/coal feed rates, this method of supercharging the bed can be used to decrease the bed size needed for a given steaming rate.

The PFBC boiler is designed for an 3-ft static bed depth and 8-ft/sec superficial velocity. The bed temperature will be 1600°F and the desired freeboard pressure is

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[24] E. C. Fox, et al., "Potential of PFB and AFB Packaged Industrial Boilers," presented at the International Symposium on Conversion to Solid Fuels, Newport Beach, CA (October 26-28, 1982); R. L. Graves, E. C. Fox, W. K. Kahl, and . F. Thomas, "Potential of PFB and AFB Packaged Industrial Boilers," presented at the American Flame Research Committee 1982 Fall Symposium, Newport Beach, CA (October 1982).

[25] G. C. Thomas, et al., "CE Availability Data Program," presented at the American Power Conference, Combustion Engineering Report, T15 6556 (1982).

3.5 atm, about the limit for commercial industrial turbochargers. The boiler shell is an upright cylinder with flanged "deep dish" drumheads (Figure 1). The cylindrical body is 25 ft high and has a 12-ft outer diameter. This height is needed for the deep bed coupled with a freeboard of about 15 ft. Again, rail shipping constraints limit the bed diameter.

Fluidizing/combustion air is introduced through a distributor tuyere plate sandwiched between the cylindrical section and the bottom drumhead. The drumhead cavity acts as a plenum and is fed by four ducts from the two turbochargers. Each turbocharger can handle 23,000 to 30,000 cu ft/min of air and can produce a maximum boost of about 3.5 atm. It has been estimated that no air preheating is necessary since the compressor work should raise the air temperature from 80° to 410°F. Unlike its counterpart being developed for utility use, the industrial PFBC concept produces no net electrical power.

After delivery, coal and dolomite are stored in separate bins sized to hold 8 hr of material. The coal bin discharges into a ring crusher to produce .25-in. maximum size feed. The limestone bin receives its material already sized and screened from the supplier. The two streams are metered, mixed, and fed to a storage hopper with a 5-minute residence time to minimize segregation. Material is metered from this vessel through a rotary feeder into a Fuller-Kinyon (F-K) pump. This pump is sized to handle about 400 cu ft/hr of crushed or sized material. With some pneumatic assistance, the discharge from the F-K pump spills into a pressurized riffle box.

The feed system splits the mixture into eight equal streams that are transported pneumatically into the bed. The pressure vessel contains about 375 boiler tubes that run the length of the vessel. This natural circulation boiler has two steam drums and two mud drums. The flue gas exhausts at 900°F into two stages of cyclones in which the suspended particulates are removed. The hot exhaust gas is then expanded in a turboexpander which provides power to compress the feed air. At this relatively low temperature, the expander is expected to have an acceptable life, although experimental verification would be necessary. The flue gas is then ducted through an economizer and out the stack.

Because of the pressurization throughout the combustion system, the purging of spent solids from the bed and removal of flyash from the dust collection system are difficult. To keep from losing pressure during operation, each disposal system must have a batch mode of removal. For the flyash removal system, each cyclone empties into pressurized tanks which, through valve arrangement, serve as large lockhoppers. In turn, these tanks discharge (at atmospheric pressure) into pneumatic conveyance lines that carry the hot ash to a silo. Spent solids are withdrawn from the vessel through a single-sided wall port just above the tuyere plate. Under normal operation, the solids leave the vessel under their own weight and fall into a pressurized tank similar to the cyclone ash tanks. After depressurization, the solids fall into a water-jacketed, screw-driven cooler. Upon exiting the cooler, the solids are conveyed pneumatically upward into a large holding tank. From this tank, the solids can be reinjected (by another F-K pump) into a vessel for load-following bed-depth control or they can be removed and discarded. The tank also serves as a prefilled bed material source for quick startup.

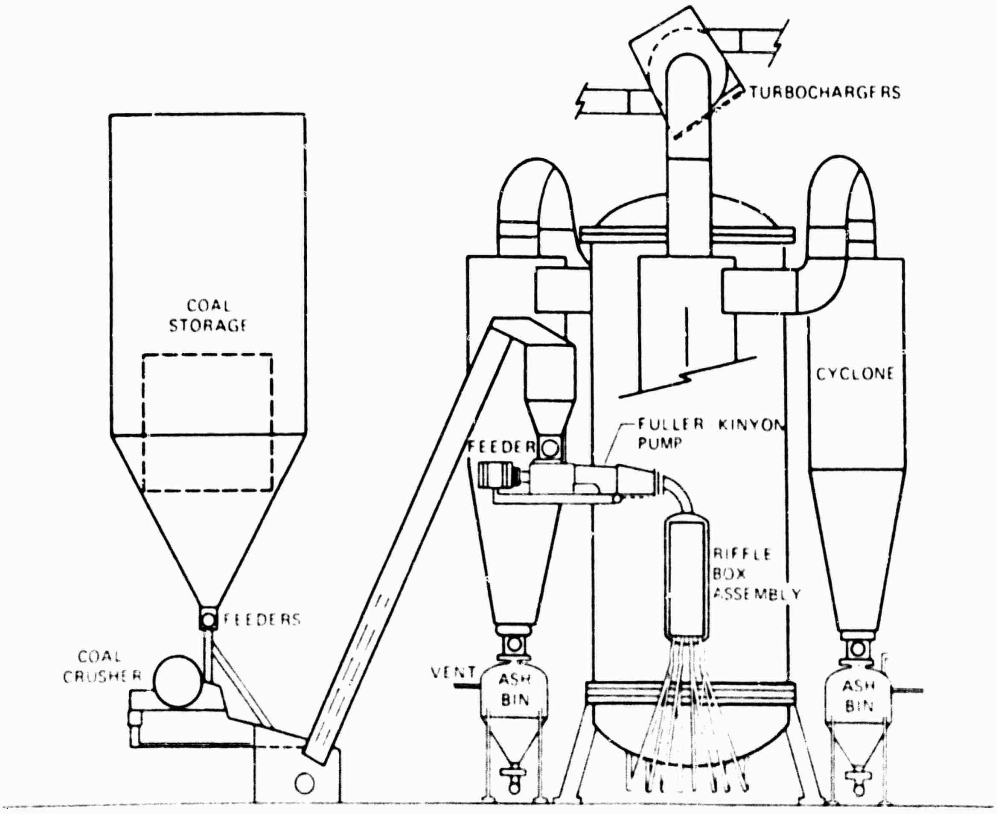

Figure 1. Pressurized-bed combustion (PFB) packaged boiler concept design.

Tables 20 and 21 give capital and operating costs for the PFBC system. The costs for coal handling, buildings, and similar auxiliary items are consistent with the other coal technologies.

Solid Fuel Retrofit Technologies

An attempt was made to derive consistent boiler fuel switching conversion costs that would be generic. This task is difficult because little data are available for some types of boiler conversions considered. Furthermore, individual retrofit cases are highly dependent on the existing boiler design and peripheral equipment. Thus, costs were estimated by determining the extent of alterations necessary for the retrofit using the assumptions in Chapter 2 and the costs for new boiler plant equipment.

Reconversion of Oil-Fired Boilers Designed for Coal Firing

This case involved boilers that were built to fire coal but were instead oil-fired for environmental concerns or other reasons (Technologies 32 and 33 in Table 2).[26] The

[26] S. A. Hathaway, et al., *Project Development Guidelines for Converting Army Installations to Coal Use*, Interim Report E-148/ADA068025 (USA-CERL, 1979); R. Singer and A. Collishaw, *Conversion of Army Heating Plants to Coal: Three Case Studies*, Technical Report E-173/ADA113947 (USA-CERL, 1982).

Table 20

Pressurized Fluidized-Bed (PFBC) Packaged Boiler*

Category	Scaling Factor	Cost
Site work	0.6	167,000
Boiler plant	0.7	2,660,000
Boiler house	0.6	390,000
Turbo/expander	0.6	370,000
Stack	0.6	170,000
Feed water treatment	0.6	340,000
Coal/dolomite handling	0.4	2,600,000
Ash handling	0.4	956,000
Wastewater treatment	0.6	280,000
Electrical	0.8	128,000
Piping	0.8	58,000
Subtotal		8,119,000
Indirects (30% of all direct cost)		2,436,000
Contingency (20% of direct and indirect costs)		2,111,000
Total		12,666,000

Capital cost equation for 30 to 200 MBtu/hr output capacity:

$$CAP = 807\ X^{0.53},$$

where cost is in 10^3 dollars and X is in MBtu/hr output capacity.

*Capital cost estimates, 180 MBtu/hr heat output capacity, 1980 dollars. This boiler is not on the market. It is included in this study for analysis of its potential, should it become available. A contingency of 40 percent would be appropriate initially, until the technology becomes common.

Table 21

Pressurized Fluidized-Bed (PFBC) Packaged Boiler—Operation and Maintenance*

Category	Cost
Direct labor and supervision	620,000
Subcontract labor and replacement parts	445,000
Electricity	30,000+30,000 (CF)
Ash disposal	185,000 (CF)
Dolomite	360,000 (CF)
Water	4,000 (CF)
Chemicals	18,000 (CF)
Total	1,095,000+597,000 (CF)

O&M cost equation for 30 to 200 MBtu/hr output capacity:

$$O\&M = 3.31X(CF) + 48.6X^{0.6},$$

where cost is in 10^3 \$/yr, CF is the plant capacity factor, and X is the steam output capacity in MBtu/hr.

*Annual nonfuel operation and maintenance cost, 180 MBtu/hr heat output capacity, 1980 dollars.

following assumptions were made when developing the reconversion capital costs in Table 22. Of course, actual costs would be highly site-specific:

- A new chain grate stoker system must be installed, which requires some boiler modifications
- No coal-handling system exists at the boiler site, so facilities for coal unloading, handling, and storage must be installed
- Equipment is needed for pneumatic transport of bottom- and flyash to an ash storage silo that supports truck loading
- A new wastewater system must be installed to treat coal pile runoff and other small wastewater discharges
- Particulate and sulfur dioxide control are needed. A baghouse and flue gas desulfurization (FGD) scrubber system must be installed.

Each item's cost in Table 22 is the same as for corresponding equipment in the spreader-stoker, coal-fired boiler plant cost estimate (Table 7), except for site work and modifications. This category covers expenses for new controls, electrical systems, piping, supports, foundations, excavation, and construction.

O&M costs are assumed identical to those in Table 8 for a new spreader stoker. This should be a good approximation for a properly retrofitted boiler.

Table 22

Reconversion From Field-Erected Oil to Coal*

Category	Scaling Factor	Cost
Stoker	0.68	585,000
Coal handling	0.38	2,349,000
Ash handling	0.38	771,000
Wastewater	0.59	342,000
Site work and modifications	0.59	300,000
Total direct costs		4,347,000
Indirects (30% of direct costs)		1,304,000
Contingency (20% of direct and indirect costs)		1,130,000
Particulate control	0.85	2,287,000
Flue gas desulfurization	0.68	3,410,000
Total		12,478,000

*Capital cost estimate, nominal 250 MBtu/hr boiler, 1980 dollars. Reconversion of field-erected boiler from oil to spreader-stoker coal boiler.

Conversion of Coal-Fired Stoker Boilers to Waste, DRDF, or Wood Firing

These cases involved converting packaged or small field-erected coal-fired stoker boilers to waste, DRDF, or wood firing. Boilers larger than 100 MBtu/hr were not considered because it is unlikely the Army would have access to such large amounts of these fuels.

An important consideration not reflected in the costs is boiler derating. A boiler designed to fire coal generally will not be able to fire fuels such as wood or DRDF at full steaming capacity, and reductions of 10 to 25 percent are expected. Conversion to municipal waste firing may require 40 to 60 percent derating. In some cases, the existing coal boiler may not be adaptable to waste firing.

Table 23 gives capital costs for renovating a coal-fired stoker boiler to fire waste, DRDF, or wood at a steaming rate of 25 MBtu/hr. It was assumed that the existing coal-fired boiler has the proper output capacity (greater than 25 MBtu/hr) to achieve this steaming rate after renovation.

The following assumptions were used to derive the boiler retrofit capital costs for waste firing:

- Boiler house expansion and improvements are necessary and cost 50 percent as much as a new boiler house (see Table 14). A tipping building is included in these costs.
- Larger storage bins, hoppers, and conveyors are needed. All equipment must be airtight with proper provisions for sanitation. The total cost is barely less than a greenfield system.

Table 23

Conversion From Coal to Waste, DRDF, or Wood*

Item	Scaling Factor	Waste	DRDF	Wood
Site and boiler house improvements	0.4	98,600		
Fuel handling and storage	0.4	1,262,000	585,400	83,800
Stoker replacement or alteration	0.68	150,600	50,000	50,000
Ash handling replacement or alteration	0.4	350,900	167,500	50,000
Utilities and controls	0.8	63,400	30,600	27,300
Subtotal		1,925,500	833,500	211,100
Indirects (30% of direct costs)		577,700	250,100	63,300
Contingency (20% of direct and indirect costs)		500,600	216,700	54,900
Total		3,003,800	1,300,300	329,300

*Capital cost estimate, heat output capacity after conversion is 25 MBtu/hr, 1980 dollars.

- The ash-handling system is replaced with only minimal salvage from the existing system.
- The existing grate is replaced by an alloy chain grate designed for waste firing.

For DRDF firing, it was assumed that:

- The existing boiler house is adequate.
- Larger watertight bins and conveyors must be installed for fuel handling and storage. The existing fuel-handling equipment is partly salvageable for a 25 percent savings over a completely new system.
- A cost allowance is needed for stoker grate and feeding equipment alterations.
- A new ash-handling system is needed although a cost credit is given for some salvage of the old system.

For wood-firing, it was assumed that:

- The existing boiler house is adequate.
- Additional storage and higher-volume conveyors are needed, but some of the original equipment should be suitable for wood. The cost can be estimated at 50 percent of a totally new system cost.
- A cost allowance is needed for stoker grate and feeding equipment alterations.
- Although wood combustion leaves only a small amount of ash, an ash sluice system will be required.

O&M costs for the retrofit boilers after renovating are assumed to be the same as for a stoker boiler built to fire the same fuel (see Table 15).

4 GAS AND OIL BOILERS

Boiler technologies that use liquid or gaseous fuels include conventional field-erected or packaged gas/oil systems, solid fuels gasification, and coal slurry retrofits, and are summarized in Table 24.

Conventional Gas- and Oil-Fired Technologies

Field-Erected Gas/Oil Boilers

The baseline field-erected gas boiler (Technology 19 in Table 24) is a natural-circulation, watertube, waterwall design by Foster Wheeler Corporation.[27] This boiler is pressure-fired with one forced-draft fan and includes 13 soot blowers. The oil-firing equipment has four air-register burners. The fuel oil system is designed to receive and store No. 6 oil, with about 30 days' storage possible in a single carbon steel cone-roofed tank. The oil system includes pumps, steam-traced piping, strainers, and oil heaters. The other auxiliary equipment, the stack, and the breaching, feedwater, and water treatment systems are similar to those described for the coal systems (Chapter 3).

The capital and operating costs are claimed to be consistent with the other technologies. Table 25 gives capital costs, and Table 26 lists nonfuel O&M costs.[28] These estimates are based on a unit designed to fire both No. 6 oil and natural gas. A user who is only going to fire gas would be likely to purchase one or more of the packaged gas units described in the next section.

Packaged Gas/Oil Boilers

Packaged gas- and oil-fired boilers (Technologies 20 and 21 in Table 24 are available in firetube and watertube designs.[29] Firetube boilers are generally smaller than 20 MBtu/hr output steam capacity, although larger units do exist. Packaged watertube boilers are available in sizes up to about 150 MBtu/hr output if shipped by rail car. Larger units are possible when using other shipping modes such as barge. Both firetube and watertube boilers have been built in sizes as small as 0.4 MBtu/hr output. Firetube boilers typically are designed to generate lower-pressure steam (30 to 150 psig saturated); higher-pressure steam usually requires a watertube boiler.

Firetube boilers are made of steel or cast iron. Cast-iron boilers cover a range of smaller sizes (less than 1 MBtu/hr) and are sometimes considered as a separate category of packaged boiler. However, separate cost equations for cast-iron gas/oil boilers are not reported here.

The cost equations for gas/oil boilers with output capacities of 5 to 23 MBtu/hr were developed for a firetube design boiler, whereas the equations for 25 to 150 MBtu/hr boilers assumed a watertube design. The minimum sizes given in Table 1 for packaged gas/oil, watertube boilers can be extended to smaller capacities, although the cost equation accuracy becomes less certain. Watertube boilers larger than 150 MBtu/hr output are field-erected rather than packaged. Multiple packaged units are quite often

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[27] Foster Wheeler, August 1981.

[28] Foster Wheeler, August 1981; PEDCo Environmental, Inc., 1979; PEDCo Environmental, Inc., January 1980.

[29] PEDCo Environmental, Inc., 1979.

Table 24

Summary of Gas and Oil Boilers

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Minimum
Conventional Gas/Oil Boilers				
19	Field-erected gas/oil	Gas/oil	500.00	50.00
20	Packaged gas/oil firetube	Gas/oil	25.00	5.00
21	Packaged gas/oil watertube	Gas/oil	150.00	25.00
Front-End Gasification				
27	Small low-Btu gasification	Coal	50.00	5.00
28	Large low-Btu gasification	Coal	500.00	40.00
29	Medium-Btu gasification	Coal	500.00	40.00
30	Wood low-Btu gasification	Wood	50.00	5.00
31	Waste low-Btu gasification	Waste	50.00	5.00
Conversion to Coal-Slurry Fuels				
37	Coal-oil mix retrofit	COM	350.00	20.00
38	Coal-oil retrofit with scrubber	COM	350.00	20.00
39	Coal-water mix retrofit	CWM	350.00	20.00
40	Coal-water retrofit with scrubber	CWM	350.00	20.00

used for systems with more than 150 MBtu/hr capacity. This may save on capital investment and add flexibility to the steam system.

For this study, packaged gas/oil boilers were assumed to be designed for firing both natural gas and either distillate oil (No. 2) or residual oil (No. 6). Table 27 gives cost information for these boilers. The capital cost difference for residual firing versus distillate firing results from (1) the fuel system and (2) designing the boiler to accommodate ash from residual oil. A residual fuel system requires oil heaters, more powerful pumps, and more expensive atomizers than a distillate oil system. Table 28 gives O&M costs. Although there is some difference in O&M costs for distillate and residual oil firing, it is slight enough to be ignored considering the scope of this study.[30] However, the fuel costs probably will be much different. Also note that the costs for the residual oil unit do not include particulate control, which may be required in some locations. This requirement would cause a substantial cost difference.

Gasification Technologies

A Wellman-Galusha gasifier design was assumed for each gasification plant configuration in this report (Technologies 27 through 31, Table 24). This design was

[30]PEDCo Environmental, Inc., August 1980.

Table 25

Field-Erected Gas/Oil Boiler*

Capital Category	Scaling Factor	Cost	
Site work	0.6	125,000	
Boiler plant	0.7	2,993,000	
Boiler house	0.4	700,000	
Stack	0.6	208,000	
Feedwater treatment	0.6	418,000	
Fuel system	0.6	217,000	
Electrical	0.8	83,000	
Piping	0.8	75,000	
Subtotal	0.8	4,819,000	
Indirects (30% of all direct cost)		1,446,000	
Contingency (20% of direct and indirect costs)		1,253,000	
Subtotal		7,518,000	
Particulate control		1,342,000	
Flue gas desulfurization**			(2,084,000)
Total		8,860,000	(10,944,000)

*Capital cost estimate, 250 MBtu/hr heat output capacity, 1980 dollars.

**Low-sulfur oil may be a better choice than flue gas desulfurization.

Table 26

Field-Erected Gas/Oil Boiler— Operation and Maintenance*

Item	Cost	
Boiler		
Direct manpower	406,000	
Electricity	38,000+2,500	(CF)**
Sublabor***	202,000	
Ash disposal	42,000	(CF)
Boiler total	646,000+44,500	(CF)
Particulate Control		
Manpower	6,000	
Electricity	17,000	(CF)
Sublabor***	25,000	
Particulate Total	31,000+17,000	(CF)

*Annual nonfuel operation and maintenance costs, 250 MBtu/hr heat output capacity, 1980 dollars.

**CF = capacity factor.

***Subcontract labor and maintenance parts.

Table 27

Packaged Gas/Oil Boilers*

Item	Firetube Boilers: Residual Oil/ Natural Gas-Fired (12 MBtu/hr)**	Firetube Boilers: Distillate Oil/ Natural Gas-Fired (12 MBtu/hr)	Watertube Boilers: Residual Oil/ Natural Gas-Fired (85 MBtu/hr)	Watertube Boilers: Distillate Oil/ Natural Gas-Fired (85 MBtu/hr)**
Boiler	71,200	65,200	666,400	606,400
Boiler house	59,700	59,700	105,000	105,000
Stack	5,000	5,000	20,900	
Feedwater treatment	26,300	26,300	108,500	108,500
Fuel system	31,000	22,700	75,200	57,900
Electrical	17,900	17,900	39,400	39,400
Piping	23,800	23,800	68,000	68,000
Other	3,600	3,600	5,300	5,300
Subtotal	230,500	224,200	1,088,700	1,011,400
Indirects (30% of direct costs)	71,400	67,300	326,600	303,400
Contingencies (20% of direct and indirect costs)	62,000	58,300	283,000	263,000
Total	371,900	349,800	1,698,300	1,577,800

*Capital cost estimates, four boilers, 1980 dollars. Source: PEDCo Environmental, Inc., January 1980.

**The first and last columns may not be realistic options for the sizes specified. They are included for more comprehensive cost comparisons.

Table 28

Packaged Gas/Oil Boilers—Operation and Maintenance*

Category	Firetube Boiler (12 MBtu/hr)	Watertube Boiler (85 MBtu/hr)
Direct labor	205,900	308,800
Supervision	65,000	103,000
Maintenance labor and materials	63,600 + 15,700 (CF)	154,400 + 38,100 (CF)
Electricity	6,900 + 15,400 (CF)	23,500 + 52,100 (CF)
Water and chemicals	2,700 (CF)	13,500 (CF)
Total	341,400 + 33,800 (CF)	589,700 + 103,700 (CF)

*Annual nonfuel operation and maintenance costs, two capacities, 1980 dollars. Source: PEDCo Environmental, Inc., January 1980.

chosen because it is considered commercially proven in the United States, and cost data are available. Furthermore, the Wellman-Galusha design can produce either low- or medium-Btu gas and operates at atmospheric pressure, which is suitable for boiler or furnace firing. Much of the gasifier plant's peripheral equipment corresponds to that in a boiler plant. When possible, it was assumed that these items are identical to help show similar capabilities between boilers and gasifiers and to establish a common basis for comparison.

The Wellman-Galusha gasifier is a counter-flow, fixed-bed, atmospheric design. The main vessel is a water-jacketed steel plate that does not require refractory lining. Coal is fed continuously (or sometimes intermittently) from overhead bins through feed tubes (equipped with slide valves) onto a revolving grate. A bed agitator or stirring mechanism is required for caking coals. Air and steam are introduced through the grate into the bottom of the coal bed (the steam is generated in the water jacket). Char combustion occurs near the grate, with gasification and pyrolysis taking place in the upper layers. As fresh coal drops to the grate, it is heated and dried by the hot gases leaving the gasifier. Ash is removed through the grate into the ash cone, which is cleaned intermittently.

If the gasifier uses air for oxidation, a low-Btu gas will be produced that is 120 to 168 Btu/std cu ft, or an oxygen plant can be used to eliminate most of the nitrogen and a 270- to 290-Btu/std cu ft (medium-Btu) gas can be produced.[31] It is not clear whether low- or medium-Btu gas production is better for firing boilers or furnaces. An oxygen plant adds expense to the gasification system and reduces efficiency. However, medium-Btu gas firing causes little or no derating, and boiler efficiency will be very close to that achieved with natural gas. Boilers firing low-Btu gas must be derated even after alterations, and will have slightly lower thermal efficiency.[32]

[31] H. F. Hartman, D. E. Reagan, and J. P. Belk, *Low-Btu Coal Gasification Processes, Vols 1 and 2*, ORNL/ENG/TM-13 (ORNL, November 1978).

[32] R. G. Schweiger, "Burning Tomorrow's Fuels," *Power*, Vol 123, No. 2 (February 1979); Tennessee Valley Authority, *Evaluation of Fixed-Bed, Low-Btu Coal Gasification Systems for Retrofitting Power Plants*, EPRI 203-1/PB 241 672 (Electric Power Research Institute, February 1975).

Coal-Fired Gasifiers To Fire Existing Boilers or Furnaces

It was assumed that large gasification/boiler systems use high-sulfur bituminous coal and require sulfur removal and other product gas treatment (Technologies 28 and 29 in Table 24). As the product gas leaves the gasifier, cyclones remove much of the particulate matter. The hot gas is then cooled by a heat-recovery boiler tied into the plant steam system. The partially cooled gas is quenched (scrubbed) with water to remove oil and tar before desulfurization. A Stretford scrubbing system desulfurizes the gas. Most of the recovered oil and tar is burned in the boiler or furnace along with the product gas.

Table 29 contains itemized capital costs for low- and medium-Btu-gas gasifier/boiler (or furnace) systems with 250-MBtu/hr output steam capacity. Capital costs were developed for many items such as coal- and ash-handling systems, buildings, water treatment, and site work by comparing them with the same items required for field-erected coal-fired boilers and scaling to size. The scaling factors are shown for each item.

Table 29 shows that many of the items cost the same with either low- or medium-Btu gas production. The oxygen plant required for medium-Btu gasification is the major difference between these systems. Lower gas volumes for medium-Btu gas production allow less expensive desulfurization equipment when compared with low-Btu gas. Items such as the gasifier and auxiliaries may have slightly different costs when comparing the two systems but, for simplicity and lack of reliable cost information, they are assumed to be identical.

Table 29

Field-Erected Coal Gasification Plants*

Category	Scaling Factor	Low-Btu Gas Plant	Medium-Btu Gas Plant
Site	0.58	250,000	250,000
Gasifier	0.68	5,886,000	5,885,000
Desulfurization	0.68	3,410,000	2,347,000
Oxygen plant	0.57		5,877,000
Water treatment	0.58	515,000	515,000
Coal handling	0.38	2,555,000	2,555,000
Ash handling	0.38	839,000	839,000
Auxiliaries	0.91	842,000	842,000
Buildings	0.38	761,000	761,000
Boiler modifications		1,592,000	796,000
Subtotal		16,650,000	20,668,000
Indirects (30% of direct cost)		4,995,000	6,200,000
Contingencies (20% of direct and indirect costs)		4,329,000	5,374,000
Total		25,974,000	32,242,000

*Capital cost estimates, 1980 dollars. Gasifier output = 312 MBtu/hr gas. Boiler output = 250 MBtu/hr steam. Sources: O. H. Klepper, et al., *A Comparative Assessment of Industrial Boiler Options Relative to Air Emission Regulations*, ORNL/TM-8144, (ORNL, July 1983); Foster Wheeler Development Corp., September 1981.

Some information about important cost items (Table 29) not covered previously should be discussed. For example, in the Wellman-Galusha gasifier, additional costs are for the necessary foundations and supports, air fans, cyclone particle separators, waste heat boiler, gas quenching system, and electrostatic precipitator.

In addition, a Stretford desulfurization system was assumed. Gas is scrubbed with a solution of aqueous sodium carbonate, sodium vanadate, and anthraquinone disulfonic acid. Dihydrogen sulfide from the gas dissolves in the solution and is partially oxidized and reacted to produce elemental sulfur. Sulfur particles are removed by froth flotation, and oxygen (air) is blown through the solution to reoxidize the scrubbing compounds to their original state. Sulfur can then be melted and transported to a storage pit.[33]

A common air separation plant is used to compress and cool the air, remove carbon dioxide and water, expand it for further cooling, and then distill and separate the nitrogen and oxygen. A nitrogen storage and distribution system is included to supply inerting gas and coal transport gas. The auxiliaries therefore include the electrical and piping systems.

It is hard to determine generically what modifications must be made to a natural gas boiler or furnace to accommodate low-Btu gas. However, modifications would almost certainly include larger gas pipes, a change to ignition systems, burners and combustion controls, alteration or replacement of induced and forced draft fans and windbox, and alteration of convective heat transfer surfaces.[34] Boiler derating of 10 percent or more is expected for low-Btu gas firing. The total cost of boiler alterations, including the controls and ducting between the gasifier and boiler, were assumed to be 15 percent of the cost for a new gas-fired boiler with equal capacity.

For medium-Btu gas firing, only minor boiler alterations are necessary. Ducting and controls linking the gasifier and boiler are still required with overall costs assumed to be 7.5 percent of a new gas-fired boiler with equal capacity. No boiler derating would be expected.

Table 30 gives O&M costs for the gasifier/boiler systems. These costs were developed from other sources[35] and by careful comparison with field-erected coal-fired stoker and pulverized-coal boiler O&M costs. Because of the similarities between coal-fired boiler plants and coal-fired gasifier plants, the O&M costs are similar.

Labor costs in Table 30 were estimated by requiring 12 additional workers for the 312-MBtu/hr low-Btu gas plant as compared to a 250-MBtu/hr stoker boiler. The medium-Btu gas plant needs four more workers than the low-Btu gasifier. Supervision costs were assumed to be the same as for a 250-MBtu/hr stoker boiler. Maintenance costs were assumed to be similar to those for a field-erected coal-fired stoker boiler.

For the low-Btu gas case, the existing boiler was assumed to be derated by 15 percent. Therefore, the boiler maintenance costs in Table 30 are for a 294-MBtu/hr output steam capacity boiler. For medium-Btu gas firing, the boiler was assumed to have 250-MBtu/hr output steam capacity. Therefore, boiler maintenance costs for a low-Btu gas system are slightly higher than for the medium-Btu gas system.

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[33] Foster Wheeler Development Corp., *Industrial Steam Supply Characteristics Program Phase II, Low and Medium-Btu Gas-Fired Boilers with Associated Gasification Plants*, FWDC #9-41-8903 (ORNL, September 1981).

[34] G. Schweiger, February 1979.

[35] O. H. Klepper, et al.; Foster Wheeler, September 1981.

Table 30

Field-Erected Coal Gasification Plants— Operation and Maintenance*

Category	Low-Btu Gas Plant	Medium-Btu Gas Plant
Fixed Costs		
Direct labor and supervision	1,362,000	1,494,000
Maintenance materials and subcontract labor	492,000	492,000
Fixed costs for boiler	522,500	488,800
Base electric power	51,800	51,800
Total fixed costs	2,428,000	2,527,000
Variable Costs		
Electric power	195,300 (CF)	195,300 (CF)
Water	6,000 (CF)	6,000 (CF)
Chemicals	175,100 (CF)	190,300 (CF)
Ash disposal	103,600 (CF)	103,600 (CF)
Waste disposal	388,000 (CF)	388,000 (CF)
Variable costs for boiler	72,400 (CF)	64,700 (CF)
Total variable costs	940,000 (CF)	948,000 (CF)

*Annual nonfuel operation and maintenance costs, 1980 dollars. Gasifier output = 312 MBtu/hr gas. Boiler output = 250 MBtu/hr steam. Sources: O. H. Klepper, et al., July 1983; Foster Wheeler Development Corp., September 1981.

Small Coal, Wood, and Waste Low-Btu Gasifiers To Fire Existing Systems

Smaller gasifier/boiler and gasifier/furnace systems were examined separately from the larger units (Technologies 27, 30, and 31, Table 24). A size upper limit of about 50 MBtu/hr (boiler output steam) was chosen to define a "small" system. For this size range, gasifiers can be shop-made and shipped by rail as a whole unit or in modular form. Shop fabrication should reduce capital costs over field erection. Also, less stringent pollution control laws cover smaller boiler systems, so it was assumed that gas desulfurization is unnecessary. Peripheral equipment costs were developed by using costs for similar equipment in packaged stoker boiler plants. Identical equipment (and therefore cost) was assumed whenever possible.

Modifying packaged oil or natural gas boilers for low-Btu gas firing can be much more difficult compared to modifying field-erected units. Because packaged boilers often are built to be as compact as possible, internal tube alterations could be expensive or not technically feasible. Derating as high as 50 percent may be necessary in some cases.

Table 31 gives capital costs for coal, wood, and waste gasifiers that fire existing boilers. A Wellman-Galusha gasifier (described previously) was assumed for all fuel types. Gasifier costs include air fans, ducting, cyclones, oil and tar removal equipment, a fuel bed stirring system (if firing caking coals), and flares.

Table 31

Small Gasifiers for Coal, Wood, or Waste*

Item	Scaling Factor	Coal	Wood	Waste
Gasifier	0.7	571,400	571,400	752,800
Buildings	0.5	167,600	167,600	205,300
Water treatment	0.6	27,900	27,900	27,900
Fuel handling	0.4	426,000	802,100	1,377,300
Ash handling	0.4	167,700	110,300	405,400
Electrical	0.8	35,800	35,800	49,500
Piping	0.8	48,200	48,200	53,900
Boiler modifications		72,400	72,400	72,400
Subtotal		1,517,000	1,835,700	2,944,500
Indirects (30%)		455,100	550,700	883,100
Contingencies (20% of directs and indirects)		394,400	477,300	765,600
Total		2,366,500	2,863,700	4,593,500

*For use with packaged boilers, capital cost estimates, 1980 dollars. Gasifier output = 25 MBtu/hr low Btu gas. Boiler output = 20 MBtu/hr steam. Compiled from the following sources: Foster Wheeler Development Corp., September 1981; Mittlehauser Corporation, January 1981; Mittlehauser Corporation, February 1981; E. D. Oliver, Technical Evaluation of Wood Gasification (Electric Power Research Institute, August 1982); R. E. Desrosiers, *Process Designs and Cost Estimates for a Medium-Btu Gasification Plant Using a Wood Feedstock* (Solar Energy Research Institute, February 1979); *A Survey of Biomass Gasification, Volume II—Principles of Gasification* (Solar Energy Research Institute, July 1979); *A Survey of Biomass Gasification, Volume III—Current Technology and Research* (Solar Energy Research Institute, April 1980).

After reviewing published literature and manufacturers' quotes, it was concluded that the gasifier unit would cost about the same as a packaged stoker boiler, assuming equivalent output capacity, expected life, and quality. Both are judged to have the same size and complexity. The gasifier has a water-jacketed shell and water-cooled eccentric revolving grate and agitator mechanism. These compare to the stoker boiler's tubes, heat exchange equipment, and chain grate.

Because wood is equally or more reactive than bituminous coal, the coal and wood gasifiers were assumed to be about the same size.[36] Waste is much more difficult to gasify and would require a large gasifier unit that could also withstand more corrosive attack.[37] The waste gasifier was assumed to be 50 percent larger than for wood or coal, and the costs were scaled accordingly. The building cost was assumed to be the same as for a packaged stoker boiler house with a gasifier that has low-Btu gas output equivalent to the boiler steam output. Water treatment requirements for a gasifier were assumed to be about one-third of that required by a boiler, and costs were scaled accordingly. Fuel- and ash-handling system costs are essentially the same as those for a packaged stoker boiler. The slight cost differences are from variations in system efficiencies.

Modifications would probably include new burners and ignitors, larger gas pipes, valves, ductwork, larger or additional air fans, and new controls. Included in this cost category are the connecting pipes and controls between the gasifier and boiler. Some reworking of the boiler internal components may be necessary, and derating up to 50 percent is expected. The total modification cost was assumed to be 15 percent of the cost for a new gas boiler with an input fuel capacity equal to the gasifier output.

Table 32 gives O&M costs for a gasifier/boiler system (or gasifier/furnace). The O&M costs were estimated by evaluating solid-fuel stoker boiler and gas-fired boiler O&M costs.[38] Costs for supervision, maintenance labor, and replacement parts are the same as for a stoker boiler that fires the same fuel and has equal output capacity. Costs for replacement parts, electricity, process water, and chemicals were estimated by comparing similar costs for stoker and gas-fired boilers.

Conversion of Oil-Fired Boilers to Coal/Oil or Coal/Water Mixture Firing

As with solid fuels, an attempt was made to derive consistent boiler fuel switching conversion costs that would be generic. Again, this task was difficult because little data were available for some types of boiler conversions considered. Furthermore, individual retrofit cases depend greatly on the existing boiler design and peripheral equipment. Thus, costs were again estimated by determining the extent of alterations necessary for the retrofit and by using consistent assumptions and the costs for new boiler plant equipment.[39]

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[36] E. D. Oliver, *Technical Evaluation of Wood Gasification* (Electric Power Research Institute, 1982); R. E. Desrosiers, *Process Designs and Cost Estimates for a Medium-Btu Gasification Plant Using a Wood Feedstock* (Solar Energy Research Institute, February 1979).

[37] *A Survey of Biomass Gasification, Volume II Principles of Gasification*, 1979; *A Survey of Biomass Gasification, Volume III--Current Technology and Research*, 1980.

[38] PEDCo Environmental, Inc., January 1980.

[39] M. E. Albert and R. D. Bessette, "Technical and Economical Implications of COM Pricing and Contracting," presented at the Third International Symposium on Coal-Oil Mixture Combustion (April 1981); D. Bienstock and E. M. Jamgochian, "Coal Oil Mixture Technology in the U.S.," *FUEL*, Vol 60 (September 1981), pp 851-864.

Table 32

**Small Gasifiers for Coal, Wood, or Waste—
Operation and Maintenance***

Category	Coal Gasifier	Wood Gasifier	Waste Gasifier
Direct labor	360,400	360,400	393,200
Supervision	103,100	103,100	103,100
Maintenance labor	96,400	96,400	162,000
Replacement parts	133,500	133,500	205,400
Electricity (60% variable)	66,400	66,400	85,600
Process water (variable)	900	900	900
Ash disposal (variable)	11,800	4,100	104,300
Chemicals (variable)	3,700	3,700	3,700
Total fixed costs	720,000	720,000	897,900
Total variable costs	56,200	48,500	160,300

*Annual nonfuel operation and maintenance costs, 1980 dollars. Gasifier output = 25 MBtu/hr low-Btu gas. Boiler output = 20 MBtu/hr steam. An annual 60 percent plant capacity factor is assumed.

Costs were estimated for a conversion of oil-fired field-erected boiler to coal/oil and coal/water mixtures (Technologies 37 through 40 in Table 24). The new fuels would be a COM that is nominally 50 percent coal by weight and 50 percent oil, and a CWM containing 70 percent coal and 30 percent water (see Table 3). These fuels may also contain some additives.

Tables 33 and 34 list boiler alterations and their estimated costs for COM and CWM. Details on the specific boiler work necessary and overall cost estimates are available elsewhere.[40] The scaling factors were estimated from other information.[41]

It was assumed that new burners and atomizers designed specifically for the new fuel would need to be installed. Soot blowers must also be installed for every tube bank that has a risk of collecting ash on the surfaces. The ash contents of COM and CWM are much higher than the furnace was originally designed to handle, and the higher the concentration of coal (and thus ash), the more severe the slagging problems. For CWM, the boiler would be derated about 10 percent more than for COM.

[40] J. A. Barsin, "Commercialization of Coal-Water Slurries," presented at the 9th Energy Technology Conference, Washington, DC (February 16, 1982); J. A. Barsin, "Commercialization of Coal-Water Slurries--II, presented at the International Symposium on Conversion to Solid Fuels, Newport Beach, CA (October 26-28, 1982).

[41] Foster Wheeler, August 1981.

Table 33

Conversion of Field-Erected Oil Boiler to Coal-Oil Mixture*

Item	Scaling Factor	Cost
Burners and atomizers	0.60	80,000
Soot blowers	0.60	200,000
Tube bank modifications	0.60	100,000
Fuel delivery and storage system	0.50	651,000
Ash removal and handling	0.38	477,000
Baghouse	0.85	728,000
Piping, pumps, electrical	0.81	40,000
Site and building modifications	0.50	200,000
Total direct costs		2,476,000
Indirects (30% of direct costs)		743,000
Contingency (20% of direct and indirect costs)		644,000
Flue gas desulfurization (including indirects and contingency)	0.68	1,666,000
Total		5,529,000

*Capital cost estimate, 1980 dollars. 250 MBtu/hr output capacity oil-fired boiler derated to 165 MBtu/hr output capacity for 50 percent coal/50 percent oil mixture firing.

Table 34

Conversion of Field-Erected Oil Boiler to Coal-Water Slurry*

Item	Scaling Factor	Cost
Burners and atomizers	0.60	100,000
Soot blowers	0.60	200,000
Tube bank modifications	0.60	300,000
Fuel delivery and storage system	0.50	651,000
Ash removal and handling	0.38	665,000
Baghouse	0.85	1,530,000
Piping, pumps, electrical	0.81	40,000
Site and building modifications	0.50	400,000
Total direct costs		3,886,000
Indirects (30% of direct costs)		1,116,000
Contingency (20% of direct and indirect costs)		1,010,000
Flue gas desulfurization (including indirects and contingency)	0.68	2,614,000
Total		8,676,000

*Capital cost estimate, 1980 dollars. 250 MBtu/hr output capacity oil-fired boiler derated to 155 MBtu/hr output capacity for 70 percent coal/30 percent water slurry firing.

Some tube bank modifications also were assumed necessary. CWM firing would require more alterations than COM because of CWM's higher ash loading. The fuel system includes 30-day storage with mixers and heaters to keep the solids suspended. Special pumps and heavy piping are required to withstand the erosive effects of COM or CWM. An ash pit must also be put into the bottom of the existing boiler. Pneumatic conveyors take ash from the pit and the baghouse to a storage silo. It was assumed that there was no existing baghouse and that one would be required after conversion. The baghouse was sized by considering the particulate loading and flue gas volume; the cost includes site work for the new fuel delivery and storage system and necessary building alterations for the baghouse, ash removal equipment, and other requirements. Sulfur dioxide scrubbers were added for both COM and CWM retrofitting. The COM scrubber is less expensive because the fuel has a much smaller sulfur content.

Table 35 gives O&M costs for the COM and CWM boiler retrofit technologies. The costs listed under the subheading "boiler plant" were derived from oil-fired and coal-fired boiler O&M costs.

For COM retrofitting, labor costs reflect the need for two additional workers over an equal-capacity oil-fired boiler. Similarly, four additional workers were assumed necessary for a CWM retrofit boiler compared to an oil-fired boiler. It was assumed that two additional subcontract laborers are needed for COM firing, with four additional workers needed for CWM firing compared to oil firing. For both COM and CWM firing, the electricity consumption was assumed to be 5 percent greater than for an equal-capacity oil-fired boiler.

Table 35

Converted Field-Erected Oil Boilers Firing Coal-Oil or Coal-Water—Operation and Maintenance

Category	155 MBtu/hr Coal-Water Slurry Retrofit Boiler	165 MBtu/hr Coal-Oil Mixture Retrofit Boiler
Boiler Plant		
Direct manpower	403,000	368,000
Electricity	24,800+1,600 (CF)*	26,300+1,700 (CF)
Sublabor**	250,000	209,000
Ash disposal	57,000 (CF)	
Boiler Total	677,800+58,600 (CF)	603,300+24,300 (CF)
Particulate Control		
Manpower	4,500	4,000
Electricity	10,600 (CF)	11,500 (CF)
Sublabor	25,800	18,200
Particulate Total	29,300+10,600 (CF)	22,200+11,500 (CF)
FGD System		
Manpower	260,000	166,000
Electricity	79,500 (CF)	41,400 (CF)
Water treatment	3,800 (CF)	2,000 (CF)
Lime and sodium	169,000 (CF)	88,100 (CF)
Waste disposal	195,000 (CF)	101,800 (CF)
FGD Total	260,000+447,300 (CF)	166,000+233,300 (CF)

*CF = capacity factor.
**Subcontract labor and maintenance parts.

5 FURNACES

This study also developed cost estimates for a variety of small furnaces. The estimates are on a basis comparable with that for the larger technologies. The reader is reminded that all technologies in this report are described in terms of their *output* capacities, although furnaces are often sized in terms of their inputs.

Here, a furnace is defined as a small unit that heats air rather than steam, and that uses gas, oil, coal, or electricity (Table 36). Except for coal, systems for each fuel are in wide use in most of the country and have a number of vendors.

Conventional Gas Furnaces

The costs for gas furnaces (Technology 41, Table 36) were estimated by contacting several heating contractors who provided cost estimates for typical heating installations and by reviewing published estimates.[42] The furnace costs in Table 37 include a factory-assembled furnace module, gas piping and flue, temperature controls, and installation including electrical hook-up. In addition to these direct costs, an allowance for indirect and contingency costs is used to be consistent with estimates for the other technologies. Because a gas-fired furnace is essentially maintenance-free, O&M costs are minimal. Maintenance involves fan lubrication and a safety inspection yearly.

High-Efficiency Gas Furnaces

The high-efficiency gas furnace uses condensing heat recovery of the latent heat in the flue gas (Technology 42, Table 36). A pulse combustion version owes its high efficiency to (1) a low air-to-fuel ratio, (2) latent-heat recovery through condensation of the water vapor in the flue gas, (3) an ample heat transfer surface, and (4) the absence of exhaust air flow when not in operation. The cost estimates are based on quotes from manufacturers. These systems are available in a limited size range and have been on the market for only a short time. Since a limited number have been sold, estimates of reliability and efficiency must be less certain than for a conventional unit. Table 38 shows the system's cost and performance. One potential difference in cost compared to the conventional gas furnace is for the drain line. A nominal drain system that can handle the moderately acidic flue gas condensate is assumed.

Oil Furnaces

The conventional oil furnace (Technology 43, Table 36) is similar to the conventional gas furnace both in its wide use and availability. The oil furnace consists of a factory-assembled furnace module, controls including safety switches, oil piping, flue, and an oil tank with about a month's oil capacity.[43] The example costs include installation of the furnace, piping, flue, and electrical connection (Table 39). Maintenance costs are again minimal for inspection and fan lubrication.

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[42] E. A. Nephew and L. A. Abbatiello, *Performance and Economics of Eight Alternative Systems for Residential Heating, Cooling and Water Heating in 115 U. S. Cities*, ORNL/CON-89 (ORNL, November 1982); R. S. Means Co., *Building Construction Cost Data 1982* (Construction Consultant Publishers, 1982); *Sears Fall/Winter Catalog 1980* (Sears Roebuck and Co., 1980).

[43] E. A. Nephew and L. A. Abbatillo, 1982; R. S. Means Co., 1982; Sears Roebuck and Co., 1980.

Table 36

Summary of Furnaces

No.	Technology	Fuel Type	Output Capacity Range (MBtu/hr) Maximum	Minimum
41	Gas Furnace	Gas	0.50	0.04
42	Gas high-efficiency furnace	Gas	0.10	0.02
43	Oil furnace	Oil	0.50	0.04
44	Oil high-efficiency furnace	Oil	0.50	0.04
46	Electric resistance furnace	Electricity	0.25	0.01
47	Heat pump	Electricity	0.54	0.024
45	Coal furnace	Coal	0.50	0.04

Table 37

Conventional Gas Furnace*

Item	Cost
Furnace	815
Electrical	100
Controls	50
Piping, flue, etc.	160
Installation	150
Subtotal	1,275
Indirects (30%)	383
	1,658
Contingency (20%)	332
Total	1,990

Capital cost equation for
40 to 500 kBTU/hr output:

$$CAP = 8.30\ X^{0.62}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.

O&M = \$20/yr.

*For 100,000 Btu/hr output gas furnace 75 percent thermal efficiency, in 1980 dollars. Compiled from: E. A. Nephew and L. A. Abbatiello, 1982; R. S. Means Co., 1982; Sears Roebuck and Co., 1980.

Table 38

High-Efficiency Oil Furnace*

Item	Cost
Furnace	1,125
Electrical	100
Controls	50
Piping, flue, etc.	200
Installation	250
Subtotal	1,725
Indirects (30%)	518
	2,243
Contingency (20%)	449
Total	2,692

Capital cost equation for
20 to 100 kBtu/hr output:

$$CAP = 7.4\ X^{0.4}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.

O&M = $50/yr.

*For 73,600-Btu/hr output, pulse gas combustion, 92 percent thermal efficiency, in 1980 dollars. Compiled from manufacturer's literature and E. A. Nephew and L. A. Abbatiello, 1982.

Table 39

Conventional Oil Furnace*

Item	Cost
Furnace	1,039
Electrical	100
Controls	75
Piping, flue, etc.	200
Installation	215
Subtotal	1,629
Indirects (30%)	489
	2,118
Contingency (20%)	423
Total	2,541

Capital cost equation for
40 to 500 kBtu/hr output:

$$CAP = 9.0\ X^{0.62}$$

Cost (CAP) is in 10^3 1980 dollars.
X is in MBtu/hr output capacity.

O&M = $40/yr.

*For 130,000-Btu/hr output gas furnace 75 percent thermal efficiency, in 1980 dollars.

High-Efficiency Oil Furnaces

There is no commercial oil furnace that condenses water vapor in the flue gas stream to recover the heat of vaporization. Nevertheless, such a furnace is included in the present study for analysis of its potential, should it become available (Technology 44, Table 36).

According to representatives from several manufacturers, an oil-fired water vapor condensing furnace would require expensive corrosion-resistant materials (mainly stainless steel) for the heat exchanger, flue piping, and condensate drain. The flue gas condensate would contain acids formed from the sulfur and nitrogen in the fuel oil, and would be more acidic than that formed in high-efficiency gas-fired furnaces. Some manufacturers claim steady-state efficiencies as high as 85 percent for noncondensing units. A forced-draft fan would probably be required.

Table 40 contains an example cost estimate for such a high-efficiency (90 percent) oil-fired furnace with a forced-draft combustion air system and flue gas condensing capability. The capital costs reflect the additional expenses for the acid-resistant metals and the forced draft system, as compared to a conventional furnace. The estimate assumes that a suitable drain is available which can handle the acid condensate.

Electric Resistance Heating

There are several methods for heating through electric resistance elements. These include baseboard heat, heating coils in the floor or ceilings, and a conventional forced-air furnace with resistance heating coils (Technology 46, Table 36). Electric boilers are also marketed for generating steam (20 kBtu/hr through 8.0 MBtu/hr) or hot water (41 kBtu/hr through 12.3 MBtu/hr).[44] The forced-air furnace is more flexible than the others, since it can incorporate an air-conditioning unit as well, and it is the simplest and least capital-intensive system available. Elements included in the cost are a shop-assembled furnace, temperature controls, installation of the furnace, and electrical connection. O&M costs are negligible, consisting of annual inspection and lubrication of the unit (Table 41).

Electric Heat Pumps

Several vendors market electric heat pumps (Technology 47, Table 36). These devices range in output capacity from 5000 Btu/hr window units to 45-ton (540,000 Btu/hr) systems for larger buildings. Only air-to-air systems with forced-air fans are considered in this study. The system efficiencies vary with vendors and with the outside air temperature. A stated heating coefficient of performance can be misleading because it usually does not include the impacts of the system defrost cycle or of cyclic operation. An overall coefficient of performance of 1.8 (with an outdoor temperature of 30°F) is judged to be typical of an efficient system. Costs for the heat pump system were estimated after obtaining cost quotes from several vendors. These quotes agreed remarkably well with the cost estimates given in another report.[45] O&M costs were taken from that report and are shown in Table 42, which includes itemized capital costs for a 60,000-Btu/hr heat pump unit (including the air-handler system). Table 43 shows the cost of a comparable air-conditioner system (the same cooling capacity).

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[44] R. S. Means Co., 1982.

[45] J. E. Christian, *Unitary Air-to-Air Heat Pumps*, ANL/CES/TE 77-10 (Argonne National Laboratory, July 1977).

Table 40

High-Efficiency Gas Furnace*

Item	Cost
Furnace	1,850
Electrical	120
Controls	100
Piping, flue, etc.	400
Installation	300
Subtotal	2,770
Indirects (30%)	831
Contingency (20%)	720
Total	4,321

Capital cost equation for 40 to 500 kBtu/hr output:

$$CAP = 15.3\ X^{0.62}$$

Cost (CAP) is in 10^3 1980 dollars. X is in MBtu/hr output capacity.

O&M = $120/yr.

*For 130,000-Btu/hr output oil furnace, 90 percent thermal efficiency, in 1980 dollars. This furnace is not on the market. It is included in this study for analysis of its potential, and should it become available.

Table 41

Electric Resistance Furnace*

Item	Cost
Furnace	420
Electrical	234
Controls	50
Installation	150
Subtotal	854
Indirects (30%)	256
	1,110
Contingency (20%)	222
Total	1,332

Capital cost equation for 10 to 250 KBtu/hr output:

$$CAP = 3.9\ X^{0.5}$$

Cost (CAP) is in 10^3 1980 dollars. X is in MBtu/hr output capacity.

O&M = $25/yr.

*For 115,000-Btu/hr output electric furnace, 100 percent efficiency, in 1980 dollars. Compiled from: E. A. Nephew and L. A. Abbatiello, 1982; R. S. Means 1982; Sears Roebuck and Co., 1980.

Table 42

Electric Heat Pump*

Item	Cost
Heat pump unit	3,310
Installation	1,248
Controls	42
Electrical	208
Subtotal	4,808
Indirect costs (30% of direct costs)	1,442
Contingency (20% of direct and indirect costs)	1,250
Total	7,500

Cost equations for heat pump with capacities from 24,000 to 540,000 Btu/hr

$$CAP = 94.3\ X^{0.9}$$

Cost (CAP) is in 10^3 dollars.
X is in MBtu/hr output capacity.

$$O\&M = 1.18\ X^{0.5}$$

*For 60,000-Btu/hr, 1980 dollars. Compiled from manufacturer's literature; J. E. Christian, 1977; E. A. Nephew and L. A. Abbatiello, 1982.

Table 43

Central Air Conditioner*

Item	Cost
Air conditioner	1,900
Installation	670
Controls	40
Electrical	200
Subtotal	2,810
Indirect costs (30% of direct costs)	843
Contingency (20% of direct and indirect costs)	731
Total	4,384

Cost equations for air conditioners from 24,000 to 500,000 Btu/hr:

$$CAP = 57.8\ X^{0.9}$$

Cost (CAP) is in 10^3 dollars.
X is in MBtu/hr.

$$O\&M = 0.5\ X^{0.5}$$

*For 57,000 Btu/hr cooling, in 1980 dollars. These costs are to be compared with those for the heat pump system in Table 42.

Coal Furnaces

The coal-fired furnace (Technology 45, Table 36) is available from very few companies. Table 44 gives example cost estimates for two sizes, based partly on quotes from one vendor. Although estimates for the furnace, stoker, and control equipment should be fairly accurate, the costs for installation, electrical connection, and coal storage are site-dependent, and here are assumed to be moderately small. For instance, for coal storage, it is assumed there is enough space in an existing building to provide for a bin with only minor structural modifications. Similar assumptions apply to the electrical connection and furnace installation.

Such a coal furnace requires a premium, double-screened coal. A coal cost premium of about $10/ton should be added to allow for this. Operating costs for the small system were developed assuming the coal stoker must be fed manually three times and the ash removed once per day for 4 months. For the large system, it was assumed that half the attendant's time would be required for 4 months. The unit's efficiency is estimated to be 65 percent.

Table 44

Coal Furnaces*

Item	125,000 Btu/hr	1.2 MBtu/hr
Furnace/stoker	2,000	6,900
Electrical	400	3,390
Controls	210	1,000
Coal storage	1,500	7,200
Installation	800	3,700
Subtotal	4,910	23,440
Indirects (30%)	1,470	7,030
Contingency (20%)	1,280	6,090
Total	$7,660	$36,560

Capital Cost Equation:

$CAP = 32.16\ X^{0.69}$, where X is in MBtu/hr and capital cost (CAP) is in 10^3 1980 dollars.

O&M Costs and Equation:

125,000 Btu/hr		1,200,000 Btu/hr	
Operation $1250/yr	(1 operator at 1 hr/day for 4 months)	$5000/yr	(1 operator at 4 hr/day for 4 months)
Repair and Maintenance $600/yr		$3200/yr	
$1850/yr		$8200/yr	

$O\&M = 7.30\ X^{0.66}$, where X is in MBtu/hr and O&M costs are in 10^3 1980 dollars.

A $10/ton premium should be included in the fuel costs ($0.42 per MBtu input).

*In 1980 dollars.

6 FUEL PRICE AND AVAILABILITY FORECASTS

This chapter explores the methods of forecasting fuel price and availability, and develops a set of projections based on forecasts from several sources. Chapter 7 will describe how these projections were used to calculate the modified present-worth factors needed to rank fuel options. In developing an actual project, current policy must be determined, as explained in Chapter 8.

The objective of this chapter is to develop a general approach to forecasting. Forecasting is a challenging discipline; although existing forecasting methods may apply similar principles, they often produce different results. The chapter begins with a review of recent prices of major fuels. Next, five forecasts published in 1981-1982 are examined, considering the sensitivity of the forecasts to the underlying assumptions and to uncertainties. The concepts of availability and price are closely related; however, because of the importance of availability in Army planning, it is considered separately here.

A set of national and regional study projections has been developed to summarize these concepts. To be consistent with most of the available forecasts, the projections do not reflect possible fuel disruptions or their impacts. If long-term trends continued without disruptions, prices would be expected to follow the trends indicated, but not exactly. That is, the paths would show a general trend, but prices would be expected to be sometimes above and sometimes below the projections.

A major assumption of most forecasts, including the projections given here, is that present trends will continue. However, the danger of this assumption is that from time to time a new trend appears, which causes prices to follow a new direction. Also, the possibility of disruptions should not be ignored, since they impact both the feasibility of functioning effectively in an emergency situation and the overall life-cycle cost of fuels. These effects are addressed further in Chapter 7.

Historical Energy Prices

Table 45 gives prices for major fuels over the last two decades. All of these fuels experienced real price minima around 1970, with most having declined steadily for some time before. However, since 1970, prices have increased markedly, with oil and gas prices nearly quadrupling and coal and electricity prices almost doubling over the decade. Gas and electricity prices have risen fairly smoothly, but the price increases in coal and oil have occurred in one or two sharp jumps.

A regional analysis is necessary to determine the possible regional impact on fuels selection criteria. Figure 2 shows the 10 Federal (Department of Energy [DOE]) regions as generally used in this report, covering the contiguous 48 states. Energy prices differ by region, as shown in Table 46. Price differences are most significant for electricity, where the price in the highest cost region was almost four times the price in the lowest cost region. Natural gas prices also differ significantly, with gas in the most expensive region costing 80 percent more than in the cheapest region. In contrast, distillate fuel oil prices are almost the same in each region. The price differences among regions shown for coal are somewhat exaggerated, because the coal produced in Region 8 has substantially less energy content per ton than most eastern coals.

Table 45

Prices of Fuels Delivered to Manufacturers, 1958-1980
(Computed from U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, Fuels and Electric Energy Consumed, M80(AS)-4.2, Table 2.)

Year	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Coal	Purchased Electricity
		a. In constant 1980 dollars per unit*			
1958	8.52 **	-- **	.78	21.14	2.39
1962	10.80	7.25	.86	18.10	2.28
1967	8.15	5.97	.74	16.60	1.97
1971	8.04	7.08	.74	19.94	1.83
1974	18.39	17.80	1.03	35.12	2.13
1975	18.54	17.19	1.38	41.72	2.45
1976	18.74	15.97	1.74	37.88	2.57
1977	20.12	17.26	2.04	37.72	2.80
1978	19.66	15.73	2.14	38.93	2.99
1979	24.21	18.88	2.30	37.90	3.03
1980	31.89	23.63	2.65	37.37	3.31
		b. In constant 1980 dollars per million Btu***			
1958	1.46**	-- **	.76	.81	7.00
1962	1.85	1.15	.84	.69	6.68
1967	1.40	.95	.73	.63	5.77
1971	1.39	1.13	.73	.76	5.36
1974	3.16	2.83	1.01	1.34	6.24
1975	3.18	2.74	1.35	1.59	7.18
1976	3.22	2.54	1.71	1.45	7.53
1977	3.45	2.75	2.00	1.44	8.21
1978	3.38	2.50	2.10	1.49	8.76
1979	4.16	3.00	2.25	1.45	8.88
1980	5.47	3.76	2.60	1.43	9.70

*Throughout this report, conversions of current to constant dollars are made using implicit GNP price deflators provided by *Survey of Current Business*, various issues, U.S. Department of Commerce, Bureau of Economic Analysis. Units: oil - barrels; gas - 1000 cu ft; coal - short tons; electricity - 10 kWh.

**Residual and distillate combined.

***Conversions as given in source for 1980: distillate - 5.824 x 10^6 Btu/barrel; residual - 6.285 x 10^6 Btu/barrel; natural gas - 1020 Btu/cu ft; coal - 26.194 x 10^6 Btu/ton; electricity - 3412 Btu/kWh. Only the conversion factor for coal will vary significantly over time. The Energy Information Administration (Annual Report to Congress 1981, Volume 1) shows a 1980 value of 25,060 x 10^6 Btu/ton and values over the period ranging up to 27,120 x 10 .

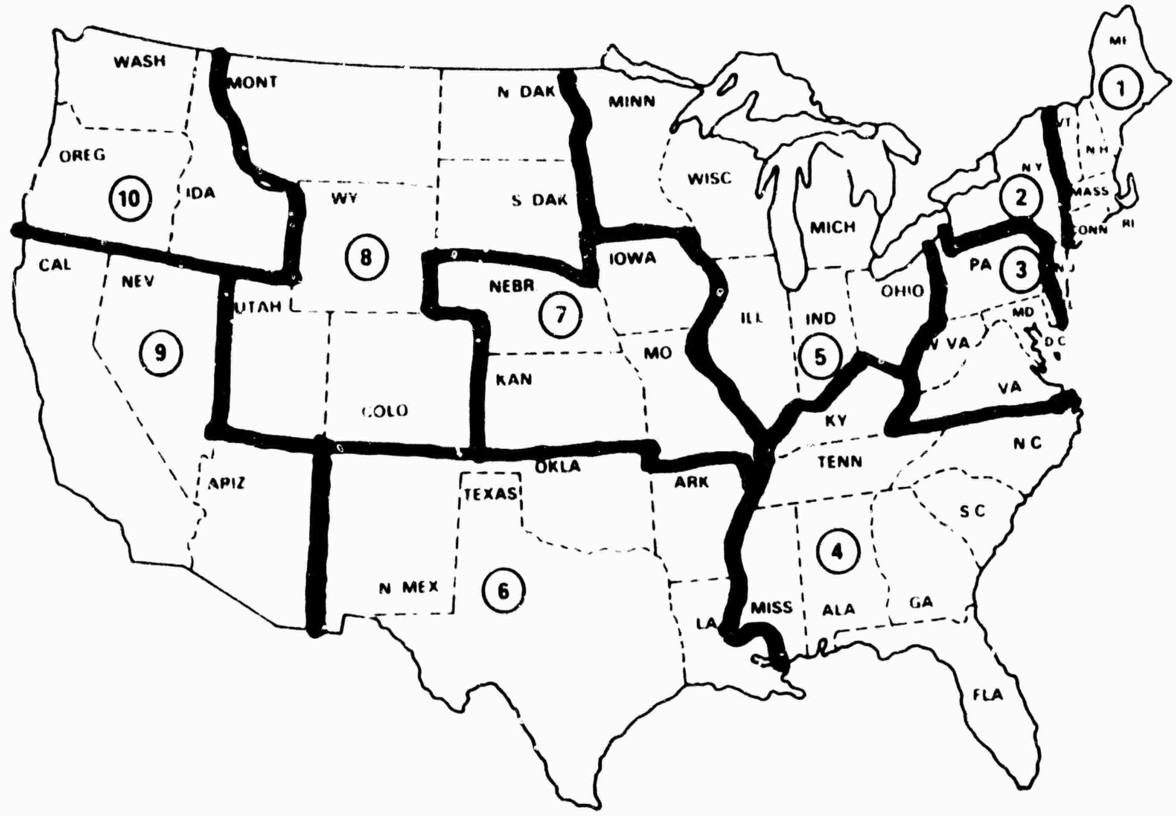

Figure 2. Federal (DOE) regions as used in this report.

Table 46

Regional Prices of Fuels Delivered to Manufacturers, 1980
(Constant 1980 Dollars)
(Computed from U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, Fuels and Electric Energy Consumed, M80(AS)-4.2 Table 3.)

	Region	Distillate Fuel Oil*	Residual Fuel Oil*	Natural Gas**	Purchased Coal‡	Purchased Electricity‡‡
1	New England	33.21	27.90	3.82	--	5.04
2	NY/NJ	31.52	26.86	3.43	40.67	4.02
3	Mid Atlantic	32.59	24.81	3.04	35.31	3.67
4	South Atlantic	31.43	21.95	2.76	39.14	3.04
5	Midwest	31.72	21.25	2.90	38.26	3.53
6	Southwest	31.24	22.28	2.14	39.67	2.93
7	Central	30.80	18.47	2.34	34.46	3.28
8	North Central	31.47	23.16	2.34	26.20	2.30
9	West	31.86	20.60	3.55	39.70	5.04
10	Northwest	34.70	21.29	3.75	37.56	1.29
		31.89	23.63	2.65	37.37	3.31

*Dollars per barrel.
**Dollars per 1000 cu ft.
‡Dollars per short ton.
‡‡Cents per kWh.

Table 47

Regional Prices of Residual Fuel Oil
Delivered to Manufacturers, 1978-1980
(1980 Dollars Per Barrel)
(Computed from U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, Fuels and Electric Energy Consumed, M80(AS)-4.2, Table 2; M78(AS)-4.2 and M79(AS)-4.2.)

Region	1978	1979	1980
1 New England	16.15	20.57	27.90
2 NY/NJ	17.26	21.27	26.86
3 Mid Atlantic	16.20	19.88	24.81
4 South Atlantic	14.95	17.36	21.95
5 Midwest	16.80	18.60	21.25
6 Southwest	16.61	17.42	22.28
7 Central	15.35	16.69	18.47
8 North Central	12.96	16.38	23.16
9 West	13.78	15.97	20.60
10 Northwest	14.23	15.91	21.29
	15.73	18.88	23.63

The regional price differences for residual fuel oils shown in Table 46 are somewhat anomalous. Table 47 compares regional prices for three different years and shows that the interregional differences can vary signficantly from one year to the next. However, more than 90 percent of residual fuel oils are consumed in Regions 1 through 6, so the comparatively wide price swings in the four western regions are of little consequence.

Table 48 compares crude oil and refined product prices. There is no fixed relationship among these prices, partly because refining margins vary with overall oil market conditions, and also because refining margins can easily be shifted among the refined products in response to shifts in relative demands for the products. For example, residual fuel oils typically account for only 10 percent of the value of refined products. Consequently, the price of residual can vary with relatively small effect on refiner profits. Furthermore, the possibilities for speculative inventory adjustments can change product prices from season to season and year to year.

Transportation costs for natural gas explain much of the regional cost differential shown in Table 46. In 1980, about 85 percent of U.S. marketed production came from Region 6; Table 46 shows that industrial prices are lowest in Region 6, increasing with distance from that region. Transportation and processing of natural gas are costly because the energy density of gas is so low. At atmospheric pressure, natural gas has an approximate heating value of only 1000 Btu/cu ft; in contrast, 1 cu ft of oil contains about 1 million Btu. Table 49 shows some representative data comparing wellhead and delivered gas prices. Processing and transportation comprise the bulk of delivered costs; the commodity price at the wellhead is only one third to one half of average delivered industrial prices and only one fifth to one fourth of commercial prices.

Table 48

Comparison of Crude Oil and Refined Product Prices
(1980 Dollars Per Barrel)

Year	Crude*	Distiliate**	Residual**
1971	6.70	8.04	7.08
1974	14.00	18.30	17.80
1975	14.74	18.54	17.19
1976	14.70	18.74	15.97
1977	15.31	20.12	17.26
1978	14.83	19.66	15.73
1979	19.31	24.21	18.88
1980	28.07	31.89	23.63

*From EIA, *1981 Annual Report to Congress*, Volume 2, DOA/EIA-0173(81)/2.
**From Table 28.

Table 49

Wellhead and Delivered Prices of Natural Gas
(1980 Cents/1000 cu ft)
(Source: Energy Information Administration, *1981 Annual Report to Congress, Volume 2, Energy Statistics*, DOE/EIA-0173(81)/2.)

	1970	1975	1980
Wellhead Price	33.3	63.2	90.4
Industrial Price	72.3	136.9	256.3
Commercial Price	150.0	191.7	339.3

Nearly 80 percent of the coal mined every year in the United States is for electric utility boilers. Most of the rest (excluding exports) is consumed in the industrial sector (about half is used in general manufacturing activities, and half is devoted to metallurgical purposes). The price data supplied here are for coal consumed by the electric utilities (those generating units of 25 MWe or larger) and the general manufacturing sector. Table 50 gives average delivered prices to each of these activities.

Table 50 shows that the utilities and manufacturers pay roughly the same prices for coal, with convergence occurring in the most recent years. This convergence is on a Btu basis, but not on a price per ton basis. Electric utilities still pay from \$6 to \$9 per ton less for coal than manufacturers. For example, during the first quarter of 1982, the average utility's cost for a ton of coal was \$34.73, but was \$41.12 for manufacturers. The difference between Btu value and ton value results from the fact that coal is not a homogeneous product and that utilities, on the average, are burning coal with a lower heating value than that burned by manufacturers.

Table 50

Average Delivered Prices of Coal
(In Constant 1980 Dollars per Million Btu)

	Manufacturing Sector*	Electric Utility**
1982 (1st quarter)	1.43	1.42
1981	1.44	1.39
1980	1.43	1.35
1979	1.45	1.33
1978	1.49	1.32
1977	1.45	1.22
1976	1.44	1.15
1975	1.59	1.15
1974	1.33	1.10
1971	.76	--
1967	.63	--

*Data in this column are computed from the U.S. Census, *Annual Survey of Manufacturers*, through 1980. After 1980, the data are computed from information provided by DOE.

**Data in this column are computed from information provided by DOE.

Table 50 also aggregates coal purchased through mid- and long-term contracts with that purchased on the spot market. Roughly 80 percent of the coal burned by manufacturers is contract coal (close to 90 percent for the utilities). Price differences between contract and spot-purchase coal vary from time to time, but normally spot-market prices are slightly more than 10 percent higher than contract prices. Table 51 shows the origin of coal burned by utilities in 1980 and the census region in which it was burned. Significant levels of coal consumption occur in all regions except the New England and Pacific regions. Major coal production regions are the Mountain and East North Central regions; the Appalachian states, found in two separate Census regions (South Atlantic and East South Central), make up another major coal-producing area. Some regions (Middle Atlantic, Mountain, Pacific, and East South Central) consume coal essentially produced from their own regions, while others consume not only their own coal, but also coal from a number of other regions. The fastest growing coal production area is the Mountain region.

Review of Current Forecasts

This section examines and compares the energy prices projected by various forecasts. Five projections are considered: the midrange forecasts of the 1981 EIA Annual Report to Congress (ARC),[46] the July 1982 updated midrange projections of the

[46]Energy Information Administration, *1981 Annual Report to Congress, Volume 3, Energy Projections*, DOE/EIA-0173 (81)/3 (U.S. Department of Energy [DOE], February 1982).

Table 51

Origin and Destination of Coal Consumed by Utilities, 1980
(Short Tons, 1000)
(Source: *Cost and Quality of Fuels for Electric Utility Plants: 1980 Annual* [DOE, Energy Information Administration, 1980])

		Origin								
Destination		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
New England	1,685.8		240.6			1,367.9	77.3			
Middle Atlantic	51,167.1		41,591.9	2,705.8		6,242.6	626.8			
East North Central	160,129.2		4,037.1	80,178.3	22.3	12,810.8	30,394.6		32,686.1	
West North Central	77,495.7		1.0	15,744.9	21,526.1	788.0	488.5	2,591.0	36,356.2	
South Atlantic	103,411.5		5,076.8	8,580.8		44,936.1	44,752.5	65.3		
East South Central	70,329.2			7,766.3		1,894.5	59,508.7		1,159.7	
West South Central	59,998.7							27,014.0	32,984.7	
Mountain	62,930.0			19.6					62,910.4	
Pacific	5,870.5								1,070.5	4,800
Total	593,017.7		50,947.4	114,995.7	21,548.4	68,039.9	135,848.4	29,670.3	167,167.6	4,800

National Energy Policy Plan (NEPP),[47] the Winter 1982/83 forecast by Data Resources, Inc. (DRI),[48] the 1982 baseline projections of the Gas Research Institute (GRI),[49] and the Spring 1982 base case projections of the American Gas Association (AGA).[50] All five projections are based on mathematical models that keep supply and demand in equilibrium by allowing prices to vary and fuel substitution to occur.

The forecasts reviewed here should not be considered as predictions of future energy prices, but rather as estimates of the most likely prices at any time. In effect, the forecasters are saying that there is a probability distribution for prices at any time and that the projected price is the one that has a 50 percent chance of being exceeded. The forecasters expect that prices will not follow the indicated path, but will sometimes be above or below it.

Another feature of the projected price path is that it represents the locus of equilibria toward which actual prices are expected to move after a perturbation. An example of such a perturbation is the runup in oil prices following the Iranian revolution. Prices overshot the new equilibrium level consistent with the reduction of Iranian exports, largely because buyers could not reliably gauge the extent of the disruption and because the dynamics of inventory adjustments to market changes have positive feedback effects. These high prices persisted for some time because demand is inelastic *in the short run*, but cannot last forever, as more recent experience has shown.

Driving Parameters

While consumers' energy prices are influenced by many factors, two considerations assume overwhelming importance. The level of economic activity, represented by the U.S. gross national product (GNP), strongly influences demand for all forms of energy, particularly in the industrial sector. The world price of crude oil directly controls oil product prices and influences the supply of and demand for substitute fuels. Neither GNP nor the world oil price is truly an exogenous factor (from outside the economy), and indeed, some of the projections examined here are merely parts of larger economic modeling systems in which the GNP and/or the oil price are endogenously determined (within the economy). Practically speaking, however, both variables can be considered exogenous in predicting future energy prices to consumers.

Gross National Product. Table 52 shows the level of the U.S. GNP assumed in four of the five forecasts. The AGA study does not specify its macroeconomic assumptions except to say that they were taken from the December 1981 forecast of Wharton Econometric Forecasting Associates.

The four forecasts assumed quite similar macroeconomic futures, with the highest GNP in the year 2000 being less than 4 percent above the lowest. Furthermore, for the period 1985 to 2000, the average compound annual growth rates are nearly the same, ranging from 2.40 to 2.53 percent. The main difference is in short-term assumptions (to

[47] *Energy Projections to the Year 2000, July 1982 Update*, DOE/PE-0029/1 (DOE, August 1982).

[48] *Energy Review* (Data Resources, Inc., Winter 1982-83).

[49] *1982 GRI Baseline Projection of U.S. Energy Supply and Demand, 1981-2000* (Gas Research Institute, October 1982).

[50] *The Spring 1982 A.G.A.-TERA Base Case*, TERA 82-1 (American Gas Association, July 13, 1982).

Table 52

U.S. Gross National Product in Selected Energy Forecasts, 1985-2000 (Billions of 1980 Dollars)

Forecast	1985	1990	1995	2000
ARC	3002	3463	3909	4316
NEPP	2962	3443	3866	4256
DRI	2919	3287	3719	4166
GRI	2973	3413	3843	4327
AGA	- - - - - - - - - - - not given - - - - - - - - - - -			

1985). The DRI forecast is lower than the rest, largely because it was made late enough to realize that no economic recovery would occur in 1982. All these projections are instream economic forecasts, and the differences among them are not significant. For instance, with a long-term income elasticity of 1.0, energy demand would differ only by 4 percent in 2000. The AGA/Wharton projection is also a conventional one.

Energy Consumption. Table 53 compares energy consumption among the forecasts. While more variable than the GNP, the consumption of total primary energy is similar among the projections. Again, the DRI forecast, being more recent, tends to show lower forecasts, a reflection of the lingering recession.

Individual fuels show somewhat greater differences. Compared with the DRI and GRI forecasts, NEPP projects a high-electricity, low-petroleum future, and the AGA expects the opposite.

World Crude Oil Prices. Table 54 shows projected world oil prices. Variability is most evident in this key parameter with the highest year-2000 price exceeding the lowest by 86 percent. In part, the differences are a result from the vintage of the studies. Oil price expectations have been falling throughout 1982 and the beginning of 1983 due to the recession and a warm winter which reduced demand and kept OPEC in disarray. The ARC and NEPP studies are the earliest and show the highest prices. However, much of the variability must be attributed to the uncertainty that remains in economic forecasting techniques. Despite similar assumptions about economic activity and the quantity of energy consumed, the studies vary markedly in their expectations of future crude oil prices.

Qualitatively, the forecasts are similar, in that they show steady or falling oil prices through 1985 and rising prices thereafter. After 1985, economic growth, though moderate by historical standards, will cause demand growth to outstrip net additions to reserves and production capacity, resulting in upward price pressure.

The qualitative viewpoint described above represents "conventional wisdom." There are minority opinions that oil prices will fall drastically in the near future, perhaps not recovering in this century, and it is important to examine them. The descriptions given here are again qualitative, as are their authors' arguments. The supply-oriented argument asserts that disunity within OPEC will lead to its breakup and that prices will fall precipitously.[51] The argument rests on the huge unexploited reserves of the Middle East and the low marginal cost of producing additional oil in this region. The high level

[51] William M. Brown, "Can OPEC Survive the Glut?" *Research Memorandum #112* (Hudson Institute, October 1981); S. Fred Singer, "An End to OPEC? Bet on the Market," *Foreign Policy* (Winter 1981).

Table 53

U.S. Energy Consumption in Selected Energy Forecasts, 1990 and 2000 (Quadrillion Btu)

	ARC	NEPP	DRI	GRI	AGA
			1990		
Total Primary	85.7	87.0	81.0	81.7	83.2
Oil	32.0	30.7	32.2	29.5	35.1
Gas	18.9	20.2	18.0	19.2	21.9
Coal	23.6	22.6	19.9	22.2	20.3
Nuclear	7.6	7.3	6.7	6.3	3.1
Other Primary	3.6	6.2	4.2	4.5	2.8
Electricity	9.3	9.8	9.1	8.9	7.8
			2000		
Total Primary		97.0	93.0	96.4	91.6
Oil		25.8	33.4	31.7	36.6
Gas		19.7	17.8	17.6	23.2
Coal		31.9	29.5	33.3	26.3
Nuclear		9.2	7.4	7.4	3.8
Other Primary		10.4	4.9	6.4	1.7
Electricity		12.3	11.5	11.2	8.6

Table 54

World Oil Price in Selected Energy Forecasts, 1985-2000 (1980 Dollars Per Barrel)

Forecast	1985	1990	1995	2000
ARC	33.00	49.00	67.00	75.00
NEPP	29.58	38.68	48.69	56.42
DRI	27.75	33.14	40.44	46.20
GRI	30.03	33.15	36.61	40.41
AGA	30.30	33.45	36.93	40.77

of oil prices since the early 1970s results fundamentally from the refusal of producing nations in the Middle East to expand production, and this viewpoint assumes that collapse of OPEC would induce the producers to act like competitive firms, expanding production to increase their profits and consequently lowering the equilibrium price level. The demand-oriented argument is that economically justifiable conservation and renewable resource options will so reduce demand for oil that prices will not rise (or will be irrelevant).[52]

More recent arguments have both supply and demand elements.[53] They assert that substitution for oil will continue despite its low prices, that growth in the nonindustrialized world will slow, that non-OPEC production will continue to grow, and that OPEC will be forced to lower prices and expand production to meet expenses.

Several factors combine to make a permanently low price scenario seem unlikely. First, much of the unexploited low-cost oil is in the Arabian Peninsula, controlled by the nations with most to gain from holding it in reserve, with the least need for extra income, and with a high degree of unity. Second, the producing nations are fully aware of the depletable nature of their oil resource and their limited nonoil resources, and thus have incentives to develop their reserves slowly. Third, a collapse of oil prices would encourage demand, while rendering many current oil frontiers in the non-OPEC world uneconomic. Surging demand and sagging exploration elsewhere would again shift control of oil toward the Middle East.

Fuel Oil Prices

Table 55 compares projected fuel oil prices among the five forecasts. (Note: Since the midrange ARC forecast crude oil price is far higher than currently expected, the low oil price ARC forecast is used throughout the rest of this section.) The prices vary markedly, and much of the variability is due to differences in assumed world crude prices. Table 56 compares fuel oil prices with the assumed prices of crude oil. Four of the studies project distillate to cost about 25 percent more than crude throughout the forecast period; the fifth expects the relative price to be lower. There is less agreement about residual fuel oil prices; they range from 22 percent below to 14 percent above the cost of crude oil. Yet the prices relative to crude have far less variability than do the absolute prices.

The differences in Table 56 reflect differences of opinion among the forecasters regarding the cost of refining crude oil and the relative values of the refined products. For a given refinery and a given crude oil, the refined products are practically joint products. Refiners can make only small changes in the proportions of the product mix. Thus, as product demands change, refiners' costs may be shifted from one product to another. Residual fuel oil prices are particularly volatile because residual oils are typically less than 10 percent of the product mix and an even lower percentage of the refiner's revenue. Thus, a small shift in the price of gasoline (>50 percent of the product mix) requires a larger shift in the price of residual oils if revenues are to be held constant.

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[52] Amory Lovins, "Expansio ad Absurdum," *The Energy Journal* (October 1981).

[53] Bruce Netschert, "The $34 Question: Whither Opec Now?" *The Energy Daily* (March 14, 1983); S. Fred Singer, "What Do the Saudis Do Now?" *The Wall Street Journal* (March 18, 1983).

Table 55

U.S. Industrial Fuel Oil Prices in
Selected Energy Forecasts, 1985-2000
(1980 Dollars Per Barrel)

Forecast	1985	1990	1995	2000
		Distillate Fuel Oils		
ARC*	34.32	45.92	60.22	
NEPP	37.46	47.01	57.71	66.12
DRI	33.74	41.13	49.52	56.20
GRI		40.32		49.14
AGA	33.33	36.14	39.29	42.74
		Residual Fuel Oils		
ARC*	31.86	41.06	55.96	
NEPP	31.33	41.74	52.02	59.80
DRI	25.17	29.74	35.81	40.47
GRI		32.96		43.51
AGA	23.56	27.63	30.47	33.63

*Low world price projection.

Table 56

U.S. Industrial Fuel Oil Prices as Percentage
of World Crude Oil Price in Selected Energy Forecasts*

Forecast	1985	1990	1995	2000
		Distillate Fuel Oils		
ARC**	132	131	123	
NEPP	127	122	119	117
DRI	122	124	122	122
GRI		122		122
AGA	110	108	106	105
		Residual Fuel Oils		
ARC**	122	117	114	
NEPP	106	104	103	102
DRI	91	90	89	88
GRI		99		108
AGA	78	83	83	82

*Volume basis.
**Low world price projection.

Of the five studies, only ARC and DRI give regional price forecasts for fuel costs. Tables 57 and 58 show these regional forecasts. Examination of the interregional differentials in the tables shows that the ARC and DRI forecasters have radically different regional patterns in mind. DRI shows lowest prices for residual fuel oils in the South (Regions 4 and 6), and highest prices on the West Coast (Regions 9 and 10). ARC shows lowest prices in the West, and highest along the East Coast. The ARC regional pattern is in better agreement with historical data than the DRI pattern. For distillates, ARC again projects a regional pattern in accord with historical data (low in mid-continent and high in the East). DRI publishes no regional distillate prices.

Natural Gas Prices

Table 59 compares natural gas prices given by the five forecasts. Both industrial and commercial prices are included, since some facilities will qualify for industrial prices and some will not. (In a functional classification system, government facilities are classified as commercial. In a system classified by size, many Army facilities will be too small for the industrial class. Nevertheless, Army fuel costs tend to be closer to industrial prices.)

The table shows large differences among the forecasts. As with fuel oil prices, much of the difference is attributable to the assumed crude oil price. Table 60 shows how industrial gas prices compare with residual fuel oil prices in the various studies. All of the studies agree that the marginal gas market is for industrial boiler fuel and that the equilibrium price of gas will be close to the energy equivalent price of residual fuel oil.

Two of the forecasts (ARC and DRI) project regional prices (Tables 61 and 62). It is helpful to think of regional gas price differences as arising from the cost of transportation. Both forecasts show prices in New England about $2 per 1000 cu ft higher than in the cheapest region, and show prices in the northeastern United States that generally increase with distance from the producing regions. Both agree that industrial gas prices will remain lowest in the major producing areas: Regions 6, 7, and 8. They disagree as to the price premium of gas on the West Coast relative to the producing area price. ARC shows the transportation differential for the West Coast to be about $2, while DRI shows it to be about 70 cents. Disagreement is also evident in transportation differentials for commercial gas. ARC projects a regional pattern similar to that for industrial gas, but DRI shows lowest prices in Regions 4 and 9 after 1990.

Coal Prices

Though the NEPP and ARC minemouth price forecasts are very similar, their forecasts of delivered prices differ considerably (Table 63). ARC projects delivered prices (across all variations of coal and on a national basis) to rise an average of 4.8 percent per year between 1980 and 1990 (the low world oil price projections); however, NEPP shows only a 2.5 percent per year rise over the same time period. By the year 1995, the ARC forecasted price is a full 29 percent higher than the NEPP price. AGA delivered price estimates start out lower than ARC's but are roughly equivalent by 1995. It is not possible to tell why ARC forecasts so greatly exceed NEPP forecasts; one can only say that the difference appears to result from different assumptions regarding transportation costs. DRI provides no aggregated coal price forecasts on a national basis to the industrial sector.

Only DRI and ARC provide regional price forecasts across all grades of coal (Table 64). DRI forecasts are higher than ARC forecasts in seven of the 10 DOE regions, and significantly higher in regions 7, 8, and 10. The higher DRI figures result from its

Table 57

Regional Industrial Fuel Oil Prices in ARC Forecast* (1980 Dollars Per Barrel)

Region	1985	1990	1995
		Residual	
1	31.53	40.77	55.72
2	32.94	42.18	57.13
3	34.27	43.53	58.47
4	31.02	40.28	55.27
5	31.30	40.55	55.55
6	31.49	40.75	55.74
7	31.63	40.91	55.91
8	30.11	39.94	55.05
9	30.22	38.83	53.05
10	30.84	39.45	53.67
Avg.	31.86	41.06	55.96
		Distillate	
1	36.57	48.12	62.55
2	36.70	48.35	62.78
3	36.01	47.71	62.14
4	36.64	48.35	62.78
5	33.27	44.97	59.40
6	32.89	44.60	59.03
7	32.76	44.46	58.89
8	34.89	47.11	61.66
9	34.44	45.60	59.33
10	34.44	45.60	59.33
Avg.	34.32	45.92	60.22

*Low world oil price projections.

Table 58

Regional Residual Fuel Oil Prices to Electric Utilities in DRI Forecast*

Region	1985	1990	1995	2000
1	23.62	30.11	35.97	40.38
2	25.01	31.75	37.80	42.27
3	24.07	30.63	36.54	41.01
4	22.24	28.48	34.08	38.43
5	23.60	29.86	35.66	40.07
6	22.24	28.41	34.15	38.43
7	23.50	29.99	35.85	40.26
8	23.88	30.49	36.35	40.76
9	26.78	33.89	40.00	44.48
10	25.96	32.89	39.00	43.53
Avg.	24.70	30.18	36.16	40.51

*From Autumn DRI 1982 forecast.

NOTE: The DRI regions do not correspond to the DOE regions. For this table, the following approximations are assumed (DOE region = DRI region): Region 1 = New England; 2 = Middle Atlantic; 3 = average Middle Atlantic and South Atlantic; 4 = average South Atlantic and East South Central; 5 = East North Central; 6 = West South Central; 7 = West North Central; 8 = average West North Central and Mountain 1; 9 = average Mountain 2 and Pacific 2; 10 = Pacific 1.

Table 59

U.S. Natural Gas Prices in Selected Energy Forecasts
(1980 Dollars Per 1000 Cu Ft)

Forecast	1985	1990	1995	2000
		Industrial		
ARC*	3.85	5.58	7.32	
NEPP	4.50	5.92	7.01	7.79
DRI	3.78	4.49	5.38	6.11
GRI		5.12		6.98
AGA	4.39	4.56	4.96	5.28
		Commercial		
ARC*	4.69	6.48	8.27	
NEPP	5.42	6.82	7.96	8.77
DRI	4.07	4.85	6.00	6.77
GRI		5.81		7.56
AGA	4.99	5.20	5.60	5.93

*Low world price projections.

Table 60

U.S. Industrial Natural Gas Prices as Percentages of
Industrial Residual Fuel Oil Prices
in Selected Energy Forecasts*

Forecast	1985	1990	1995	2000
ARC**	78	88	85	
NEPP	77	95	92	87
DRI	94	95	94	95
GRI		95		98
AGA	117	104	102	99

*Energy basis.
**Low world oil price projections.

Table 61

Regional Natural Gas Prices in ARC Forecast*
(1980 Dollars Per 1000 Cu Ft)

Region	1985	1990	1995
	Industrial		
1	5.20	7.06	8.86
2	5.00	6.70	8.69
3	4.29	6.08	7.81
4	3.80	5.63	7.42
5	4.17	5.95	7.65
6	3.49	5.15	6.81
7	3.38	5.27	6.96
8	3.27	4.96	6.78
9	4.71	6.52	8.46
10	4.11	5.73	7.50
Avg.	3.85	5.58	7.32
	Commercial		
1	5.97	7.84	9.64
2	5.85	7.55	9.54
3	5.00	6.78	8.52
4	4.22	6.05	7.84
5	4.57	6.35	8.05
6	4.53	6.18	7.84
7	3.97	5.86	7.56
8	3.81	5.49	7.32
9	4.78	6.59	8.53
10	5.14	6.76	8.53
Avg.	4.69	6.48	8.27

*Low world oil price projections.

Table 62

Regional Natural Gas Prices in DRI Forecast
(1980 Dollars Per 1000 Cu Ft)

Region	1985	1990	1995	2000
1	5.51	6.42	7.39	8.04
2	4.26	5.14	6.05	6.72
3	4.22	5.01	5.96	6.66
4	3.98	4.73	5.75	6.48
5	3.98	4.88	5.90	6.60
6	3.21	3.90	4.68	5.40
7	3.84	4.73	5.75	6.47
8	3.77	4.57	5.58	6.29
9	3.74	4.45	5.43	6.15
10	3.91	4.52	5.49	6.29
Avg.	3.67	4.40	5.25	5.96
Commercial				
1	5.51	6.17	7.16	7.79
2	4.12	4.98	6.09	6.98
3	4.05	4.81	5.84	6.63
4	3.70	4.42	5.45	6.20
5	3.98	4.78	5.79	6.50
6	3.21	3.85	5.52	6.50
7	3.84	4.57	5.63	6.41
8	4.02	4.83	5.82	6.50
9	3.50	4.39	5.41	6.17
10	4.12	4.88	6.06	6.98
Avg.	3.96	4.75	5.85	6.61

Note: The DRI regions do not correspond to the DOE regions. For this table, the following approximations are assumed (DOE region = DRI region): Region 1 = New England; 2 = Middle Atlantic; 3 = average Middle Atlantic and South Atlantic; 4 = average South Atlantic and East South Central; 5 = East North Central; 6 = West South Central; 7 = West North Central; 8 = average West North Central and Mountain 1; 9 = average Mountain 2 and Pacific 2; 10 = Pacific 1.

Table 63

U.S. Industrial Coal Prices in Selected Energy Forecasts (1980 Dollars Per Short Ton)

Forecast	1985	1990	1995	2000
ARC*	46.96	51.45	56.65	
NEPP	37.30	41.12	43.82	46.29
AGA	42.24	46.96	54.83	63.81

*Low world oil price projections.

Table 64

Regional Industrial Coal Prices in ARC*/DRI Forecasts (1980 Dollars Per Short Ton)

Region	1985	1990	1995
1	50.38/52.58	53.80/59.54	58.25/63.14
2	52.03/47.86	55.43/55.05	59.63/59.77
3	43.89/48.53	46.71/56.62	49.94/61.58
4	60.07/48.53	68.59/57.30	77.16/61.58
5	45.35/49.43	49.24/57.30	52.02/60.67
6	55.10/55.72	61.52/71.00	72.79/81.11
7	38.86/51.00	42.05/61.79	43.99/70.11
8	28.63/42.24	30.05/52.13	32.19/58.87
9	59.61/49.43	66.41/65.16	72.81/75.95
10	45.75/54.15	48.67/68.75	53.24/78.64
National	46.96/-----	51.45/-----	56.65/-----

*Low world oil price projections.

Table 65

U.S. Electricity Prices in Selected Energy Forecasts (1980 Cents per kWh)

Forecast	1985	1990	1995	2000
		Industrial		
ARC*	3.99	4.12	4.40	
NEPP	5.89	6.37	7.23	7.25
DRI	4.91	5.15	5.47	5.81
AGA	4.35	5.38	6.06	6.74
GRI		5.12		5.53
		Commercial		
ARC*	5.61	5.76	6.08	
NEPP	6.03	6.62	7.59	7.69
DRI	6.41	6.28	6.39	6.61
AGA**	5.79	6.78	7.37	8.00
GRI		6.28		6.22

*Low world oil price projections.
**Residential/commercial.

assumptions of real annual increases in labor wages and capital costs, unlike the projected price stability of these factors by other forecasters, who see prices rising only through resource depletion in the east, and through transportation rate hikes. The DRI figures also include significant real increases in transportation rates.

Electricity Prices

There are significant differences in national price forecasts for electricity (Table 65). ARC projections are the lowest and NEPP projections the highest. By 1995, NEPP projections for the commercial sector are 25 percent higher than ARC projections, and 64 percent higher for the industrial sector. DRI figures fall between the two extremes. ARC projections show only 0.8 percent and 1 percent annual increases in the commercial and industrial sectors, respectively, between 1985 and 1995; NEPP projections show annual price increases of 2.3 percent and 2 percent for these sectors over the same time period. DRI projects no price increases in the commercial sector and only a 1 percent annual increase in the industrial sector.

Only DRI and ARC provide regional breakouts of electricity forecasts (Table 66). Since DRI national price projections are higher than ARC's, it is not surprising that their regional figures are usually higher. This is especially true for regions 8 and 6. DRI's numbers for region 8 appear to be far out of line. This region depends on low-sulfur subbituminous coal mined in the region for electricity, and in 1980, the average cost of electricity to the industrial sector was 2.26 cents/kWh. Despite constant price minemouth coal prices, DRI has the cost of electricity doubling in this region by 1985, whereas ARC sees declining electricity prices. The projection of the current study is for stable or declining prices in this region, although not quite as optimistically as ARC. Both DRI and ARC appear to assume complete natural gas price deregulation between 1980 and 1985, greatly impacting region 6 which depends greatly on natural gas for electricity production. It now appears that complete deregulation of natural gas prices will take longer to phase in. ARC projections also assume a good deal of coal and nuclear substitution for natural gas for electricity production in region 6. Since near-term substitution of these sources now appears less likely, the higher price projections of DRI for this region seem more reasonable.

Prices of Unconventional Fuels

Electricity, coal, oil, and gas are the principal fuels presently used in the industrial and commercial sectors. Certain other fuels may be cost-effective in special situations now or in the future. Four are examined here: coal-liquid mixtures, solid waste, wood, and uranium. Only uranium prices are projected by any of the aforementioned studies.

Fuel costs of nuclear energy production are projected in the ARC and DRI studies (Table 67). Both show the fuel cost component of nuclear energy remaining fairly constant throughout the period. Currently, the cost is $0.80 per million Btu.[55]

None of the other fuels is presently sold in large, organized markets. For a large customer, such as an Army facility, to use such a fuel in the near future, it would either have to provide the fuel itself or contract with an entrepreneur willing to enter the business.

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[55] H. I. Bowers and J. G. Delene, *Preliminary Analysis - Regional Projections of Nuclear and Fossil Electric Power Generation Costs* (Engineering Technology Division, ORNL), presented at IEA-ORAU Workshop on Costs of Nuclear Power Plants, Oak Ridge, Tennessee, January 12, 1983.

Table 66

Regional Electricity Prices in ARC*/DRI Forecasts
(1980 Cents Per kWh)

Region	1985	1990	1995
		Industrial	
1	5.40/6.42	5.85/6.48	6.25/6.61
2	4.46/5.72	4.43/5.35	4.91/5.61
3	3.88/5.28	4.00/5.19	4.36/5.69
4	3.77/4.50	3.99/4.78	4.45/5.37
5	3.96/4.87	3.97/5.20	4.22/4.86
6	4.89/5.47	5.32/6.10	5.33/6.98
7	4.68/4.45	4.01/4.55	4.11/4.48
8	2.53/4.30	2.19/4.51	1.95/4.40
9	5.32/5.53	5.57/5.57	6.09/5.42
10	1.51/2.86	1.89/3.29	2.38/3.87
National	3.99/4.91	4.12/5.15	4.40/5.47
		Commercial	
1	6.87/8.54	7.32/8.05	7.72/7.85
2	7.07/7.55	7.05/6.75	7.52/6.71
3	5.41/7.57	5.54/6.29	5.90/6.57
4	5.00/6.26	5.23/6.13	5.68/6.47
5	5.49/6.61	5.50/6.54	5.75/5.90
6	6.04/7.21	6.47/7.43	6.49/8.07
7	5.84/4.96	5.16/4.99	5.26/4.83
8	4.01/5.01	3.68/5.08	3.43/4.86
9	6.11/6.55	6.36/6.35	6.88/6.06
10	2.72/3.34	3.10/3.64	3.59/4.17
National	5.61/6.41	5.76/6.28	6.08/6.39

*Low world oil price projections.

Table 67

Uranium Fuel Costs in Selected Energy Forecasts
(1980 Dollars Per Million Btu Thermal)

Forecast	1985	1990	1995	2000
ARC	0.7	0.8	0.8	
DRI	1.1	1.1	1.1	1.1

As a fuel, wood plays a small but significant role in the wood products industries and as a secondary residential fuel. Both markets are special cases. The wood products industries have special access to wood and wood wastes, yet purchase much of their needed energy in other forms because the value of wood as fiber or structural material exceeds its opportunity cost as a fuel. Koppelman found that in Maine, even waste products like sawdust and shavings were valued more highly for animal bedding than for fuel and that little unused waste was available at wood product mills in the state.[55]

Estimates for various regions of the United States (Maine, Tennessee Valley,[56] Northeast,[57] and North Wisconsin and Upper Michigan[58]) put present costs for chipped wood as fuel at $30 to $40 per dry ton ($1.7 to $2.3 per million Btu). Only one estimate has been found to be significantly lower. In northern California, loggers must gather, pile, and burn the slash (waste limbs) because the fire hazard associated with leaving it is too high. A proposal for gathering and chipping the slash for fuel estimated costs of only $20 to $25 per dry ton ($1.1 to $1.4 per million Btu).[59] This low price results from two factors: the negative opportunity cost of the resource and a centrally controlled and highly organized harvesting system. Spiewak, et al., find delivered wood costs to be $1.9 to $2.5 per million Btu for all regions (New England, Middle Atlantic, Southeast, Lake States, Gulf Coast) except the Mountain and Pacific Coast regions, where they estimate the costs to be $2.5 to $3.0 per million Btu.[60]

The cost of various forms of municipal solid waste as fuel is tied to the cost of conventional waste disposal. The waste must be processed before burning, but this processing cost is offset by the savings of the costs for conventional disposal and the value of other materials recovered. A 1979 study by the Office of Technology Assessment (OTA) found energy recovery to be economical only in locations with very high conventional disposal costs.[61] Disposal costs vary greatly among locations, ranging from $2 to $10 per ton.

Municipal solid waste can be burned almost as received or at various stages of refinement. Two "grades" are considered here: (1) a coarse grade with only ferrous materials and large pieces removed and (2) a refined grade (densified refuse-derived fuel [DRDF]) which has also been shredded, classified to remove glass and dirt, and compressed into pellets. Very little cost information is available besides that in the OTA report. OTA found a refined grade of fuel to have a processing cost of about $22 per ton and a ferrous scrap recovery value of about $2 per ton. If landfill cost savings are $10 per ton, then the resulting net cost of DRDF is $10 per ton of waste processed or $1.10

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[55] E. Kopelman, et al., *Feasibility Study Production - Production of High Grade Solid Fuels from Wood Waste and Peat Using the Koppelman Process*, DOE/RA-50305 (DOE, November 1981).

[56] J. C. Roethali, et al., *Economic Analysis of Using Valley Hardwoods for Fuel Energy*, TVA-2010271 (Tennessee Valley Authority, February 1981).

[57] J. S. Munson, ed., *Issues in the Use of Wood as an Energy Source in the Northeastern U.S.*, BNL-51196 (May 1980).

[58] North Central Forest Experiment Station, *Forest Residues Energy Program*, TID 28416 (Forest Service, U. S. Department of Agriculture, April 1978).

[59] Sverdrup/Sverdrup Technology Inc., *Wood Fuel for Power Generation at Wendel, California, Volume 1, Executive Summary*, DOE/ET/27244-T1 (DOE, May 1981).

[60] I. Spiewak, et al., *Technical Analysis of the Use of Biomass for Energy Production*, ORNL/TM-7919 (Engineering Technology Division, ORNL, August 1982).

[61] Office of Technology Assessment, *Materials and Energy from Municipal Waste*, Congress of the United States, Washington, DC, OTA-M-93 (July 1979).

per million Btu of fuel recovered. If landfilling costs only $2 per ton, then the resulting fuel cost is $2 per million Btu. No data are given for the coarse grade of fuel. If estimated processing costs are one quarter of the cost to make DRDF, then the resulting fuel cost will range from $-0.7 to $+0.2 per million Btu.

Coal-oil mixtures (COM) are suspensions of pulverized coal in residual fuel oil. Their advantage is that they allow relatively cheap coal to be burned in boilers designed for residual oil. The technologies for making COM and burning them are still under development and COM are available only from small-scale plants. Early estimates concluded that a 50-50 mixture could be produced for about 18 to 24 cents per million Btu above the costs of the fuels contained in the mixture, while a coal company that manufactures small quantities for use in experimental applications gives estimates that imply a cost of $1.90 per million Btu above fuel costs.[62] Three factors that might account for the ten-fold difference are: (1) the small-scale, noncommercial nature of existing mixing plants, (2) the tendencies of new technologies to cost more than initial estimates, and (3) lack of competition. Coal-water slurries are another means of burning coal in a facility not designed for handling solids. No cost estimates have been found for preparing such a slurry for an industrial boiler. Much literature is available on coal slurry pipelines as a transportation alternative to railroads. However, differences of scale appear to make this literature irrelevant. Coal-water mixtures require less stabilizing additive and should be cheaper to mix than coal-oil mixtures.

Sensitivity and Uncertainties

Mathematical models are useful for structuring thinking, ensuring consistency, and facilitating computation. However, models cannot solve the forecaster's two fundamental problems: (1) understanding the system and (2) specifying events outside the system. A forecaster must *assume* the structure of the system and *assume* values for exogenous variables whether or not a formal mathematical model is used. Thus, there are two kinds of errors: those from specifying the structure and parameters incorrectly, and those from assuming a future scenario different from what ultimately will occur. This section examines the state of the modeling art and the influence of uncertainties about structure and scenarios. The Energy Modeling Forum (EMF) of Stanford University has examined 10 economic models of the world oil market and used these models to explore a number of scenarios.[63]

Figure 3 graphically demonstrates the variability of results due to model structure. Each model was run with a common set of reference assumptions, yet the computed prices in 2000 (in 1981 dollars) ranged from $42 to $90 per barrel. The models even disagreed on the 1980 price ($29 to $44 per barrel) because many were benchmarked to earlier years. The differences among the models' results are largely attributable to the particular effects and feedbacks the models deal with and the form in which the effects are expressed.

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[62] P. D. Bergman, et al., *Economic Considerations for Industrial Firing of Coal-Oil Mixtures*, Pittsburgh Energy Research Center, presented at 1st International Symposium Coal-Oil Mixture Combustion, St. Petersburg, Florida, (May 8-10, 1978); G. T. Hawkins, *Operation of a Central Preparation Plant for Coal-Oil-Water Mixtures*, Coal Liquid, Inc., Louisville, KY, presented at 2nd International Symposium on Coal-Oil Mixture Combustion, November 27-29, 1979, CONF-791160-Vol. 1; Gary Kapp, Island Creek Coal Company, personal communication, February 1983.

[63] Energy Modeling Forum, World Oil, *Summary Report*, EMF Report 6 (Stanford University, February 1982).

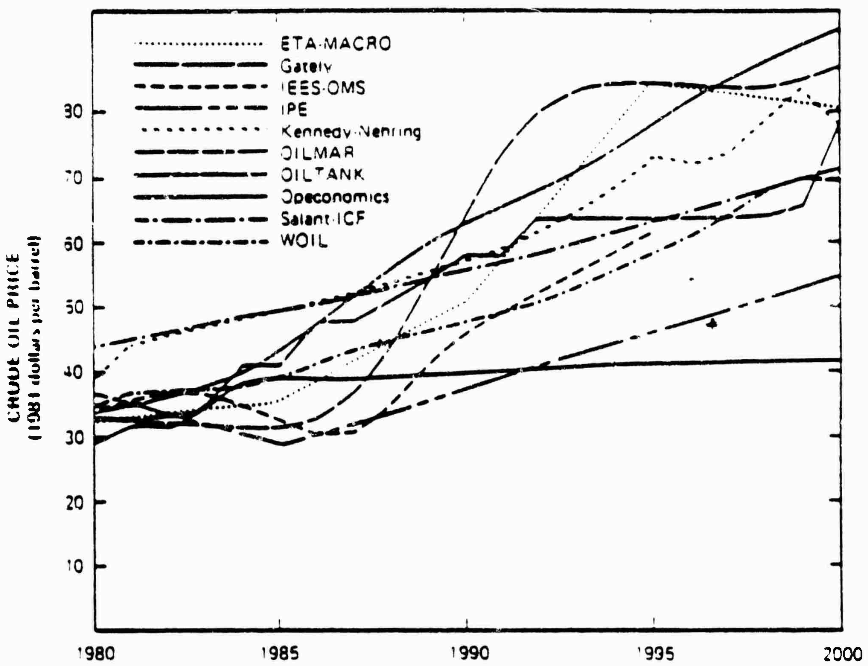

Figure 3. World oil price projection for several models. (From Energy Modeling Forum, "World Oil," *Summary Report*, EMF Report 6, [Stanford University, February 1982].)

As might be expected, the models' responses to alternative scenarios vary similarly. These responses are expressed as percentage changes from the reference case price and are given as median, minimum, and maximum percentages. The response of price to two factors--economic activity and non-OPEC supplies--is examined.

One alternative scenario considered a low economic growth case; from the results, EMF computed the percentage price reduction per 10 percent gross national product (GNP) reduction. For 1990, the median price reduction was 24 percent and the range was 12 to 40 percent. For 2000, the median was 10 percent, with a range from 6 to 17 percent.

Another alternative assumed that import demand is reduced by means other than price incentives. This demand shift is equivalent to an increase in exports by non-OPEC producers, since it reduces demand for OPEC oil and OPEC is the marginal producer. Thus, this scenario can be used to examine both situations. For 1990, each 1 million barrel-per-day import reduction (or non-OPEC export increase) reduces oil prices 1.6 to 5.0 percent, with a median of 3 percent. For 2000, the range is 0.8 to 2.9 percent and the median is 1.8 percent.

The EMF experiments convey a very important perspective on the state of the economic modeling art. Figure 3 and the results discussed above suggest that modeling uncertainty is as great as or greater than uncertainty about input scenarios. Questions about structure or about key parameters like demand electricity are at least as important as questions about exogenous events like economic growth. Clearly, there is great uncertainty in any forecast.

Comparing the midrange forecasts of ARC and NEPP provides further evidence of the importance of structure in model results. Both the ARC and the NEPP studies used a range of input assumptions or scenarios. Each study gives high, low, and midrange estimates of the world crude oil price for each forecast year (Figure 4). The range of

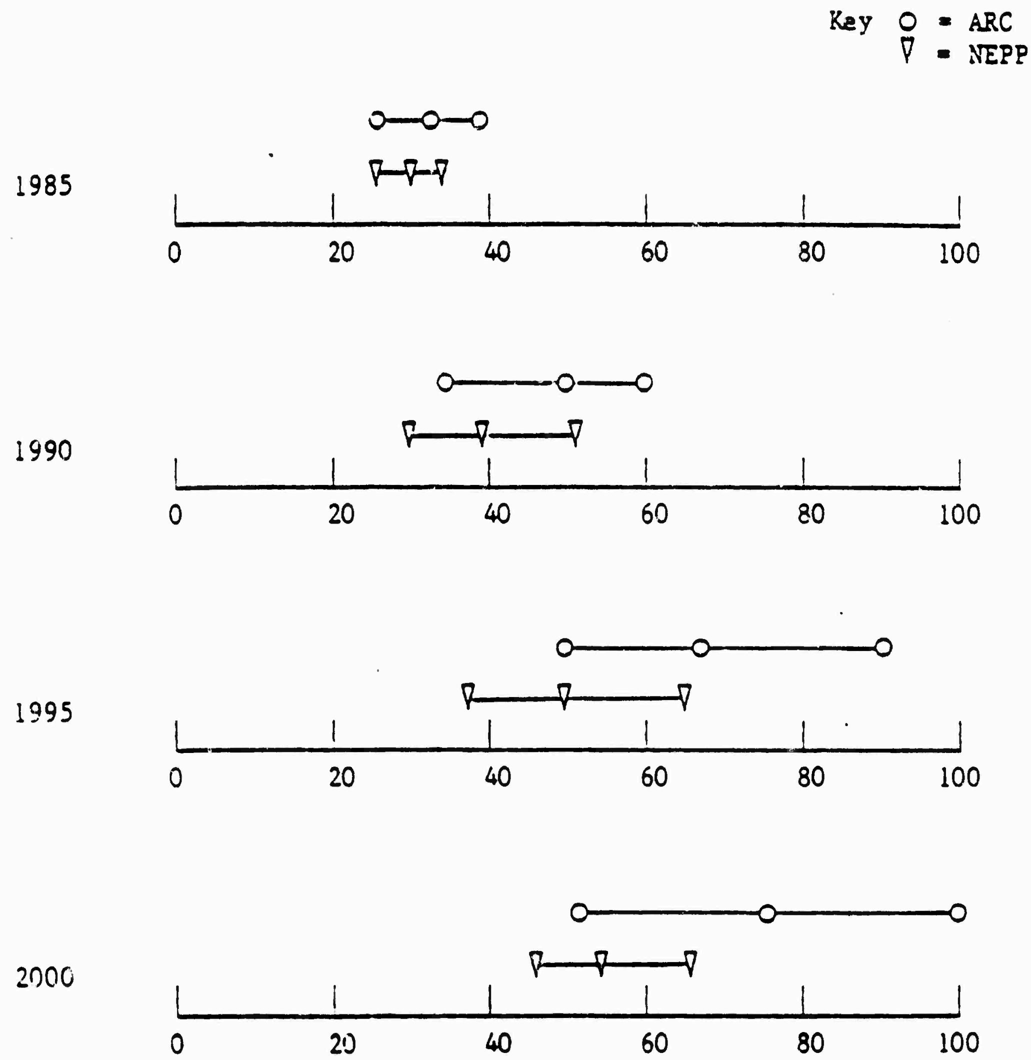

Figure 4. ARC and NRPP world oil price projections (in 1980 dollars).

scenarios covered is wide, particularly in the ARC studies, giving rise to a wide range of possible prices. In the view of the analysts, the midrange estimates in both studies represent the most likely future, and are the ones discussed earlier in this report. Midrange prices are quite divergent after the 1980s, with the NEPP estimates about 25 percent lower than comparable ARC estimates. However, the key assumptions in each study are similar: moderate economic growth in the OECD, and faster growth in the developing countries; no large change in OPEC producing capacity and no major supply disruptions; and the non-OPEC developing countries remaining as net importers. Table 68 compares realized economic growth and the supply and demand balance for oil in the two studies. These estimates are very close, and it is apparent that the ARC and NEPP predictions differ because of different model structure and parameter estimates, not because they have a different view of the future. Differences between their midrange estimates are attributable to uncertainty about how the economic system works.

This uncertainty in the economic model results only confirms what should be obvious from the recent price furor in OPEC. Several years ago, virtually all forecasters saw only one direction for oil prices. Yet recent events have shown that these prices can fall, and that more and more forecasters do not view this price collapse as an aberration. The lesson should be clear that the numbers in our forecasts are uncertain, and that the Army must be flexible to adjust to unexpected circumstances.

Table 68

Comparison of Projections, ARC and NEPP

Comparison of Projections - 1985

	ARC	NEPP
Gross Domestic Product Index (1980=100)		
U.S.	114	113
NonCommunist World (NCW)		
Oil Consumption (MMBD)		
U.S.	17.2	15.7
Other OECD	19.5	20.9
OPEC	3.3	3.5
Other NCW	8.9	9.4
Total	48.9	49.5
Oil Production (MMBD)		
U.S.	9.7	9.9
Other OECD	5.0	5.2
OPEC	25.8	26.1
Other NCW	8.4	8.4
CPE Exports	0.0	0.1
Total	48.9	49.7

Comparison of Projections - 1990

	ARC	NEPP
Gross Domestic Product Index (1980=100)		
U.S.	132	136
NCW		138
Oil Consumption (MMBD)		
U.S.	16.2	15.2
Other OECD	19.8	21.2
OPEC	4.6	4.6
Other NCW	9.8	10.6
Total	50.4	51.8
Oil Production (MMBD)		
U.S.	10.1	9.2
Other OECD	5.2	5.5
OPEC	25.7	28.6
Other NCW	9.3	9.4
CPE Exports	0.0	-1.0
Total	50.4	51.7

Table 68 (Cont'd)

Comparison of Projections - 1995

	ARC	NEPP
Gross Domestic Product Index (1980=100)		
U.S.	149	
NCW		
Oil Consumption (MMBD)		
U.S.	16.4	14.4
Other OECD	20.0	19.8
OPEC	6.4	5.8
Other NCW	11.1	10.8
Total	53.9	50.9
Oil Production (MMBD)		
U.S.	10.9	9.0
Other OECD	5.7	5.8
OPEC	27.7	26.6
Other NCW	9.7	10.2
CPE Exports	0.0	-1.0
Total	53.9	50.6

Comparison of Projections - 2000

	ARC	NEPP
Gross Domestic Product Index (1980=100)		
U.S.	164	161
NCW		173
Oil Consumption (MMBD)		
U.S.		13.7
Other OECD		19.7
OPEC		7.1
Other NCW		11.3
Total		51.7
Oil Production (MMBD)		
U.S.		8.6
Other OECD		6.1
OPEC		26.1
Other NCW		11.1
CPE Exports		-1.0
Total		50.9

Fuel Availability

Fuel Oil

Availability is a concept difficult to separate from price. In general, oil is always available at some price, although the price might get so high that for practical purposes, oil becomes unavailable. Supply disruptions lead to sharp price increases, and some users would choose to use less fuel or switch to alternate sources.

Two such disruptions have been experienced in the past decade. In each case, crude oil and refined products remained available, but the price discouraged many uses. This rationing effect of prices tended to decrease consumption to the reduced level of supply. Price rationing was not allowed to operate by itself, of course; in the United States, price and allocation regulations were in effect, and these regulations affected the product mix and the allocation of products to geographic region and to marketer. Some users were given priority of access, but no users were excluded from the market by fiat. (A possible exception is users of transportation fuel who experienced rationing by inconvenience [e.g., even-odd plans and queues]). Considerable exclusion by fiat was experienced by natural gas users during shortages.)

From this literal viewpoint, availability of oil should not concern Army bases. Under any feasible rationing system, Army bases would receive priority. However, at a less literal level, availability would be a concern. Would future disruptions make oil too expensive? Will future scarcity reduce the public acceptability of burning oil? Answering these questions must consider price.

The studies and projections (Tables 52 through 68) assume that no oil supply disruptions will occur during the analysis period. Aside from the unwillingness of the OPEC members to significantly expand production capacity, political factors are excluded. (That is, capacity expansion is constrained by politics, but capacity use is governed by economics. The studies assume that OPEC capacity will be held nearly constant throughout the period.) The studies' authors do not believe this no-disruption scenario; however, they argue that the character and timing of future disruptions are highly uncertain and that disruptions are short-term phenomena that have little effect on the long-term path of oil prices. A disruption raises prices markedly for awhile, but these prices cannot be sustained; after the disruption, the price drifts slowly down toward the level that would have applied without the disruption. Real price adjustments from the 1979 disturbances are still occurring.

Disruptions cannot be ignored in the present analysis, however, because these prices are to be used to compute the discounted present worth of energy costs over the equipment's lifetime. A short-term disruption near the beginning of the period might markedly influence costs, even though the effect of disruption is not detectable at the end of the period.

To examine the effect of a disruption on the present-value calculation, the baseline oil prices were altered by arbitrary price increases to simulate the effect of a supply loss. After a disruption, prices were assumed to peak at twice the baseline value 1 year later and to decline linearly to the baseline by the fifth year. Assuming a 7 percent real discount rate and a project life of 20 years, the present worth of one barrel per year was computed for various disruption scenarios. Surprisingly, the timing of the disruption is not critical. A disruption occurring in year number 5 raises the present worth by 13 percent over the baseline; if it does not occur until year 15, the present worth is still 10 percent above baseline. This result occurs because the high discount rate is offset by a

high escalation rate of oil price increase (4.0 percent annually from years 5 through 20) and by the fact that the price rise is assumed proportional to baseline prices. However, the size of the price increase is critical; if the increase is doubled, so is the percentage above baseline. Historically, small supply losses have caused prices to double or triple. Thus, it would not be unreasonable to expect the present worth of fuel oil costs to be as much as 20 to 30 percent higher than those computed from Tables 70 and 71 (see pp 107-108) if a supply disruption occurs. To include the impact of such a disruption in this analysis, the present worths of fuel oil costs have been increased by a conservative 10 percent.

Most observers expect the Middle East to remain a volatile region and expect that political events will lead to future disruptions. Judging from past events, a moderate supply loss is unlikely to affect prices in a soft market, such as is extending into the mid-1980s. (This glut is largely the result of the last disruption.) However, once there is upward pressure on oil prices again, a relatively small event could readily trigger a sharp escalation of oil prices. Such an event is highly likely in the next 10 to 20 years. If it occurs, we can expect renewed emphasis on alternatives to oil.

Natural Gas

Natural gas markets have traditionally been balanced by quantity, rather than price, variations. Seasonal demand fluctuations are accommodated in part by storage, but interruptible contracts and expensive supplemental sources such as synthetic natural gas (manufactured by reforming light petroleum products) have also played important roles. Large nonseasonal fluctuations like the shortage during the early 1970s or the excess during the early 1980s require more drastic quantity adjustments, e.g., curtailing some customers or shutting in some wells.

The natural gas market is likely to move away from adjustment mechanisms based on quantity in the next few years and to behave more like a conventional market regulated by prices. The nature and extent of these institutional changes is not well defined, but some movement in this direction appears necessary for the success of the decontrol experiment.

Two questions are relevant to the Army's concerns about natural gas availability: "How likely is curtailment?" and "How much might prices be affected in a price-balanced market?" The answers to both questions will depend on the relative mix of price-changing and quantity-changing adjustment mechanisms in the market. It is likely that even the mixture of adjusting mechanisms will differ from situation to situation. Nevertheless, some useful generalizations can be made.

Curtailment is not a concern for any Army base with a firm contract and no supply alternatives. No curtailment ranking will leave a military facility without fuel. Installations with dual fuel capabilities are likely to be curtailed if a shortage is severe enough to cause economic hardships. In such a case, the alternate fuel is likely to be more expensive than the gas would have been. Installations supplied under interruptible contracts should expect to be interrupted occasionally under normal market conditions; during shortages, gas would simply be unavailable to interruptible customers. Again, the cost of being interrupted or curtailed is the additional cost of the alternate fuel (probably oil) that must be used during the curtailment.

Curtailment is the price customers pay to hold monetary gas prices constant when demand exceeds supply. Freeing prices to respond to over- or undersupply obviates the need to curtail. The authors believe that gas prices will be freed somewhat to respond to market conditions and that the price of gas will move in parallel with the price of oil under normal circumstances.

What will happen under abnormal circumstances such as the oil supply disruptions of 1973 and 1978? Will gas prices follow oil? For several reasons, prices are unlikely to respond so quickly. First, some portion of gas reserves will be committed under long-term contracts because of the expensive investment required for transporting gas to market; the contracts will slow the response of gas prices to higher oil prices. Second, most customers will continue to buy both the commodity (gas) and delivery services from local distributors, despite a tendency for larger industrial and commercial users to purchase the commodity directly from producers. Thus, much delivered gas will remain subject to the cost of service regulation by state public utility commissions, where price responses will be slowed despite automatic passthrough provisions. Third, some of the response of oil prices to supply disruptions, especially in 1978-1979, has been attributed to overreaction by spot market buyers. Even if a spot market for gas were to develop, it would be much smaller than the oil market, and gas is not a likely commodity for speculative inventory accumulation as is oil. Therefore, gas prices are expected to be less volatile than oil prices.

It must be stressed that the institutional structure of gas marketing under decontrol has only begun to develop and the various possibilities have not been examined in detail. The factors noted above have not been quantified. Simulations performed to estimate the present-value costs to an oil-burning facility of an oil supply disruption were reported above. The costs of the same oil supply disruption to a gas-burning installation can only be speculated upon; they will be lower, perhaps only half as large.

Gas import disruptions are also a possibility, particularly the import projects having OPEC members as suppliers (e.g., Algeria and Indonesia). Presently, imports are only 5 percent of total gas supply, and about 80 percent of these imports are from Canada. The projections cited above show non-North American imports increasing, but remaining less than 5 percent of supply.[64] Disruption of imports at these levels would not be negligible, and, if coupled with an oil supply disruption, could cause a rapid runup in gas prices.

Although full recontrol is considered unlikely, the possibility cannot be ruled out. Probable consequences of such action would be a repeat of the past decade. During times of short supply, existing customers would be protected at the expense of potential new customers, and foresighted customers who could use other fuels would lose their low-cost gas supplies.

Coal

The enormous reserves of coal in the United States constitute a very favorable feature of that resource. This abundance is the factor leading analysts to forecast relative coal price stability in the future. With the vast resource base in the United States there is very little importing of coal from other nations; thus, the dangers of resource dependency present with oil are not found with coal.

Another positive feature is that, unlike the situation with natural gas, the government has not placed price controls on coal. Thus, the market sets minemouth prices. The large number of coal suppliers works against industry price-setting collusion. The extensive amount of interregional trade in coal also lessens the danger of regionally based monopolies forming.

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[64] *1981 Annual Report to Congress, Volume 3, Energy Projections; Energy Projections to the Year 2000, July 1982 Update; Energy Review; 1982 GRI Baseline Projection of U.S. Energy Supply and Demand, 1981-2000; The Spring 1982 A.G.A.-TERA Base Case.*

For these reasons, it is frequently noted that coal use in this country is more constrained by *demand* than by *supply*. In other words, coal production and deliveries could be substantially increased if there were increases in demand due to booming economic growth and/or a strong desire for coal as an alternative to competing fuels. In short, the availability of coal to meet the desired demand is definitely one of the major advantages associated with its use.

Unfortunately, all availability considerations are not unambiguously positive. *Labor strikes* and *transportation monopolies* are the foremost coal availability concerns. The history of coal production in this country is replete with coal miner strikes for better wages or working conditions. Railroads currently hold a monopoly over the long-distance transport of western coal to its primary markets. Most forecasts assume there will be no major transportation bottleneck, and that western coal will capture a larger part of the market because of its abundance, low production costs, and low sulfur content. However, these forecasts could prove wrong if the railroads, using their monopoly power, price western coal out of many markets.

Though not quite as serious as the previous two concerns, a number of other uncertainties could impact availability and price:

1. *Federal leasing policies* in the west determining the extent of land allowed to be exploited for coal production.

2. *Labor wages and productivity* could impact minemouth prices. Labor productivity has declined since 1970 while wages have risen.

3. *Capital equipment costs and requirements* may be determining factors in the use of coal. The extent and nature of pollution control equipment could change over time.

4. *Environmental concerns* to include clean air and water standards, reclamation policies, acid rain, and CO_2 emission. Federal and state policies regarding these issues could move back and forth (as they have in the past), depending on the political leaders in power.

5. *Severance taxes* have been increased substantially in a few western states. This could begin a trend toward eastern coal states.

Electricity

There should be no short- or intermediate-term concerns regarding the availability of electricity. Generating capacity coming on-line now was ordered by the utilities when their own forecasts were pointing toward continued 7 percent annual growth rates in consumer demand. Since actual growth rates have been below half this level since 1973, there is now a surplus of generating capacity that should exist for at least another decade. The 1981 ARC projects national reserve margins of 38 percent, 39 percent, and 35 percent in the years 1985, 1990, and 1995, respectively. In the past, a 20 percent reserve margin has generally been considered acceptable to assauge availability concerns. Only the Mid-Atlantic region comes close to the 20 percent reserve margin. Virtually all forecasts assume growth rates for electricity demand to be around 3 percent. This constitutes conventional wisdom at this time, since it neither predicts a return to old growth rates, nor accepts a continued stagnation in electricity demand.

Plausible, though not necessarily probable, scenarios can be constructed that indicate possible problems during the 1990s and beyond. Though this may seem far into

the future, it should be remembered that licensing and construction times of a decade or more are typical for large-scale coal or nuclear power facilities in this country.

There are two distinct, but related, concerns regarding future capacity availability: (1) that utilities will be unable to add necessary baseload capacity in the future because of financial constraints[65] and (2) utilities will significantly underforecast the demand for electricity.[66] Should either case materialize, undercapacity would result and it would be necessary to use expensive ways of producing electricity (e.g., oil and gas baseload plants, combustion turbines, renewable resources). Though the projections made in this section have not assumed the most favorable ARC construction schedules, and hence have to some extent factored in the costs of uncertainty, no accounting has been made for a possible resurge of electricity demand at 1960s growth levels.

Nonconventional Fuels

For the most part, the nonconventional fuels considered here are not widely available. Organized markets for supplying large quantities of wood, waste, or COM as fuel do not exist. Any use of such energy sources would require new organizations or arrangements to procure, process, and deliver the fuel to the user. The materials themselves, particularly wood and waste, will always be available at a price, just as coal and oil will be physically available. But the stability of the marketing organizations and arrangements for nonconventional fuels should be examined carefully. A supplier's business failure could cause the fuel to become suddenly unavailable, and finding a replacement might be quite costly. The implication is that caution should be exercised before commiting to a nonconventional fuel. The safest technologies for such fuels will permit dual-fuel capability. Organized markets for uranium do exist in this country and abroad, so uranium unavailability should not be a problem.

Fuel Price Projections

This section presents a set of fuels price projections. These study projections are not the products of a new mathematical model. Rather, the task has been to analyze and distill the many available forecasts and information sources, and to present a set of regional projections for the fuels of interest. To be consistent with most of the available forecasts, possible fuel disruptions or their impacts have not been incorporated. Rather, as described above in the section *Review of Current Forecasts*, the following set of forecasts represents the best estimate of the most likely prices at any given time. For example, the 1986 slump in oil prices would be regarded as temporary. Prices are not expected to follow the indicated paths exactly, but will sometimes be above and sometimes below them.

Driving Parameters

The main factors influencing future energy prices are the level of economic activity and the world price of crude oil. The "best guess" estimates of both parameters provided here are close to the levels forecast by DRI and given in Tables 52 and 53. The DRI estimates are more current and, in the case of oil prices, more middle of the road

[65]Energy Information Administration, *Impacts of Financial Constraints on the Electric Utility Industry*, DOE/EIA-0311 (DOE, December 1981).

[66]Chauncey Starr and Milton F. Searl, "U. S. Generating Requirements for Economic Growth, 1990-2000," *Public Utilities Fortnightly* (April 29, 1982).

than the extremes taken by the ARC or GRI and AGA forecasters. Table 69 gives estimates for this study.

Fuel Oil Prices

Crude oil prices are the most important determinant of fuel oil costs.. As shown in Table 56, there is considerable consensus among the forecasters that the national average distillate price will be about 25 percent higher than crude oil, and that number is assumed in the projections. Residual prices are more controversial; 95 percent of crude has been adopted as approximately representing the mean of the model results.

Tables 70 and 71 show projected regional prices. The tables were constructed assuming that price differences among the regions would continue in the historical pattern (similar to the regional pattern projected by ARC). That is, prices are generally highest on the East Coast and lowest in the West.

Natural Gas Prices

All five forecasts reviewed[67] computed equilibrium industrial gas prices to fall at about the same rate as the price of residual fuel oil. It is important to realize that this conclusion results from computing the intersection of supply and demand curves for gas, not from a preconceived notion that the two fuels "ought to" be priced similarly because they are natural competitors. The conclusion is somewhat robust with respect to assumed supply conditions, because the demand curve for gas is rather flat in the vicinity of the price of residual. (An estimated 30 percent of the industrial gas market can switch to residual oil almost instantaneously if prices warrant.)

However, this approximate equality of national average prices does not hold within each region. One reason is that transportation costs differ for the two fuels. The low energy density of gas (1000 Btu/cu ft) compared with oil (1 million Btu/cu ft) makes gas relatively expensive to ship from a producing area to a consuming one. Tables 72 and 73 show regional prices of industrial and commercial gas, respectively. Lowest prices are in the major producing areas (Regions 6, 7, and 8), with prices increasing with distance from the source.

Coal Prices

Regional price forecasts for the three specific kinds of coal of interest here (high-sulfur bituminous, low-sulfur bituminous, and low-sulfur subbituminous) are only found in ARC. One could make across-the-board adjustments to these figures, based on a higher-price scenario (DRI) or a lower-price scenario (NEPP). Arguments can be marshalled to support either scenario. DRI's assumption of real increases in labor wages and capital costs, for instance, is not unreasonable. On the other hand, current coal prices and lagging coal production appear to support NEPP forecasts up to this time. Since those arguments tend to balance one another, there is no compelling justification for across-the-board adjustments to the ARC (low world oil case) figures.

While using ARC figures for the base in Tables 74 through 76, some numbers in various regions have been altered by the authors to reflect what is felt to be more

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[67] *1981 Annual Report to Congress, Volume 3, Energy Projections; Energy Projections to the Year 2000, July 1982 Update; Energy Review; 1982 GRI Baseline Projection of U.S. Energy Supply and Demand, 1981-2000; The Spring 1982 A.G.A.-TERA Base Case.*

Table 69

Expected Driving Parameters

	1980	1985	1990	1995	2000
U.S. GNP (Billion 1980 dollars)	2633	2920	3290	3720	4170
World Crude Oil Price (1980 dollars per barrel)	28	27	34	41	49

Table 70

Expected Residual Fuel Oil Prices by Region*

	Region	1980	1985	1990	1995	2000
		In 1980 Dollars Per Barrel				
1	New England	27.90	27.72	34.40	41.01	48.64
2	NY/NJ	26.86	28.04	34.71	41.33	48.95
3	Mid Atlantic	24.81	26.52	33.20	39.82	47.44
4	South Atlantic	21.95	24.32	31.00	37.61	45.23
5	Midwest	21.25	25.07	31.75	38.37	45.99
6	Southwest	22.28	25.01	31.69	38.30	45.93
7	Central	18.47	23.06	29.74	36.35	43.97
8	North Central	23.16	23.75	30.43	37.04	44.67
9	West	20.60	23.00	29.67	36.29	43.91
10	Northwest	21.29	23.37	30.05	36.67	44.29
	National	23.63	25.65	32.30	38.95	46.55
		In 1980 Dollars Per Million Btu				
1	New England	4.43	4.40	5.46	6.51	7.72
2	NY/NJ	4.26	4.45	5.51	6.56	7.77
3	Mid Atlantic	3.94	4.21	5.27	6.32	7.53
4	South Atlantic	3.48	3.86	4.92	5.97	7.18
5	Midwest	3.37	3.98	5.04	6.09	7.30
6	Southwest	3.54	3.97	5.03	6.08	7.29
7	Central	2.93	3.66	4.72	5.77	6.98
8	North Central	3.68	3.77	4.83	5.88	7.09
9	West	3.27	3.65	4.71	5.76	6.97
10	Northwest	3.38	3.71	4.77	5.82	7.03
	National	3.75	4.07	5.13	6.18	7.39

* These projections assume that no major oil supply disruption occurs.

Table 71

Expected Distillate Fuel Oil Prices by Region*

	Region	1980	1985	1990	1995	2000
				In 1980 Dollars Per Barrel		
1	New England	33.21	36.13	44.89	53.65	63.63
2	NY/NJ	31.52	36.25	45.01	53.77	63.74
3	Mid Atlantic	32.59	35.61	44.37	53.13	63.10
4	South Atlantic	31.43	36.25	45.01	53.77	63.74
5	Midwest	31.72	32.89	41.64	50.40	60.38
6	Southwest	31.24	32.54	41.30	50.05	60.03
7	Central	30.80	32.42	41.18	49.94	59.91
8	North Central	31.47	34.16	42.92	51.68	61.65
9	West	31.86	32.94	41.70	50.46	60.44
10	Northwest	34.70	32.94	41.70	50.46	60.44
	National	31.89	33.75	42.50	51.25	61.25
				In 1980 Dollars Per Million Btu		
1	New England	5.73	6.23	7.74	9.25	10.97
2	NY/NJ	5.43	6.25	7.76	9.27	10.99
3	Mid Atlantic	5.62	6.14	7.65	9.16	10.88
4	South Atlantic	5.42	6.25	7.76	9.27	10.99
5	Midwest	5.47	5.67	7.18	8.69	10.41
6	Southwest	5.39	5.61	7.12	8.63	10.35
7	Central	5.31	5.59	7.10	8.61	10.33
8	North Central	5.43	5.89	7.40	8.91	10.63
9	West	5.49	5.68	7.19	8.70	10.42
10	Northwest	5.98	5.68	7.19	8.70	10.42
	National	5.50	5.82	7.33	8.84	10.56

*These projections assume that no major oil supply disruption occurs.

Table 72

Expected Industrial Natural Gas Prices by Region

	Region	1980	1985	1990	1995	2000
				In 1980 Dollars Per 1000 Cu Ft		
1	New England	4.21	5.47	6.49	7.52	8.70
2	NY/NJ	3.59	4.73	5.76	6.78	7.96
3	Mid Atlantic	3.07	4.65	5.67	6.70	7.88
4	South Atlantic	2.79	4.39	5.42	6.44	7.62
5	Midwest	2.95	4.55	5.57	6.60	7.78
6	Southwest	1.95	3.42	4.44	5.47	6.65
7	Central	2.43	3.93	4.96	5.98	7.16
8	North Central	2.54	4.08	5.11	6.14	7.32
9	West	3.70	4.33	5.36	6.38	7.56
10	Northwest	2.90	4.43	5.46	6.48	7.66
	National	2.56	3.97	5.00	6.02	7.20
				In 1980 Dollars Per Million Btu		
1	New England	4.10	5.33	6.33	7.33	8.48
2	NY/NJ	3.49	4.61	5.61	6.61	7.76
3	Mid Atlantic	2.99	4.53	5.53	6.53	7.68
4	South Atlantic	2.72	4.28	5.28	6.28	7.43
5	Midwest	2.88	4.43	5.43	6.43	7.58
6	Southwest	1.90	3.33	4.33	5.33	6.48
7	Central	2.37	3.83	4.83	5.83	6.98
8	North Central	2.48	3.98	4.98	5.98	7.13
9	West	3.61	4.22	5.22	6.22	7.37
10	Northwest	2.83	4.32	5.32	6.32	7.47
	National	2.50	3.87	4.87	5.87	7.02

Table 73

Expected Commercial Natural Gas Prices by Region

	Region	1980	1985	1990	1995	2000
		In 1980 Dollars Per 1000 Cu Ft				
1	New England	4.83	6.06	7.09	8.11	9.30
2	NY/NJ	4.38	5.32	6.35	7.38	8.56
3	Mid Atlantic	3.70	5.24	6.27	7.29	8.47
4	South Atlantic	3.25	4.99	6.01	7.04	8.22
5	Midwest	3.24	5.14	6.17	7.19	8.37
6	Southwest	2.85	4.01	5.04	6.06	7.24
7	Central	2.56	4.52	5.55	6.58	7.76
8	North Central	3.05	4.68	5.70	6.73	7.91
9	West	3.97	4.92	5.95	6.98	8.16
10	Northwest	4.20	5.03	6.05	7.08	8.26
	National	3.42	4.57	5.59	6.62	7.80
		In 1980 Dollars Per Million Btu				
1	New England	4.71	5.91	6.91	7.91	9.06
2	NY/NJ	4.27	5.19	6.19	7.19	8.34
3	Mid Atlantic	3.61	5.11	6.11	7.11	8.26
4	South Atlantic	3.17	4.86	5.86	6.86	8.01
5	Midwest	3.16	5.01	6.01	7.01	8.16
6	Southwest	2.78	3.91	4.91	5.91	7.06
7	Central	2.50	4.41	5.41	6.41	7.56
8	North Central	2.97	4.56	5.56	6.56	7.71
9	West	3.87	4.80	5.80	6.80	7.95
10	Northwest	4.09	4.90	5.90	6.90	8.05
	National	3.33	4.45	5.45	6.45	7.60

Table 74

Expected High-Sulfur Bituminous Prices by Region

	Region	1980*	1985	1990	1995	2000
		In 1980 Dollars Per Short Ton				
1	New England	--	48.18	51.40	55.29	59.47
2	NY/NJ	40.67	42.71	45.48	48.71	52.17
3	Mid Atlantic	35.31	38.62	42.63	47.07	51.97
4	South Atlantic	39.14	45.02	49.22	53.12	57.33
5	Midwest	38.26	37.78	41.38	43.10	46.50
6	Southwest	39.67	41.73	44.87	53.38	60.00
7	Central	34.46	37.53	43.12	46.24	49.79
8	North Central	26.20	31.24	33.96	36.00	38.16
9	West	39.70	41.73	47.45	52.13	57.27
10	Northwest	37.56	47.39	52.14	56.84	61.96
	National	37.37	41.85	45.16	49.19	53.46
		In 1980 Dollars Per Million Btu				
1	New England	--	2.02	2.16	2.32	2.50
2	NY/NJ	1.55	1.79	1.91	2.04	2.19
3	Mid Atlantic	1.35	1.62	1.79	1.98	2.18
4	South Atlantic	1.49	1.89	2.07	2.23	2.41
5	Midwest	1.46	1.59	1.74	1.81	1.95
6	Southwest	1.51	1.75	1.88	2.24	2.52
7	Central	1.32	1.58	1.81	1.94	2.09
8	North Central	1.00	1.31	1.43	1.51	1.60
9	West	1.52	1.75	1.99	2.19	2.40
10	Northwest	1.43	1.99	2.19	2.39	2.60
	National	1.43	1.60	1.72	1.88	2.04

*U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, "Fuels and Electric Energy Consumed," M80(AS)-4.2, Table 3. 1980 regional totals are for all grades and types of coal consumed, not just high-sulfur bituminous.

Table 75

Expected Low-Sulfur Bituminous Prices by Region

	Region	1980*	1985	1990	1995	2000
			In 1980 Dollars Per Short Ton			
1	New England	--	58.02	62.79	68.23	73.86
2	NY/NJ	40.67	54.46	57.57	62.42	67.68
3	Mid Atlantic	35.31	50.16	55.38	61.14	67.50
4	South Atlantic	39.14	52.87	56.30	62.17	68.25
5	Midwest	38.26	49.92	53.65	57.96	62.62
6	Southwest	39.67	42.48	46.19	55.60	66.50
7	Central	34.46	42.67	47.88	54.53	60.63
8	North Central	26.20	31.29	35.34	36.30	37.21
9	West	39.70	42.07	50.15	55.30	60.97
10	Northwest	37.56	44.26	48.24	56.85	70.00
	National	37.37	46.82	51.35	57.05	63.52
			In 1980 Dollars Per Million Btu			
1	New England	--	2.44	2.64	2.87	3.10
2	NY/NJ	1.55	2.29	2.42	2.62	2.84
3	Mid Atlantic	1.35	2.11	2.32	2.58	2.83
4	South Atlantic	1.49	2.22	2.36	2.61	2.87
5	Midwest	1.46	2.10	2.25	2.43	2.63
6	Southwest	1.51	1.78	1.94	2.33	2.79
7	Central	1.32	1.79	2.01	2.29	2.55
8	North Central	1.00	1.31	1.48	1.52	1.56
9	West	1.52	1.77	2.11	2.32	2.56
10	Northwest	1.43	1.86	2.03	2.39	2.94
	National	1.43	1.97	2.16	2.40	2.67

*U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, "Fuels and Electric Energy Consumed," M80(AS)-4.2, Table 3. 1980 regional totals are for all grades and types of coal consumed, not just high-sulfur bituminous.

Table 76

Expected Low-Sulfur Subbituminous Prices by Region

	Region	1980*	1985	1990	1995	2000
			In 1980 Dollars Per Short Ton			
1	New England	--	71.25	78.27	86.20	94.94
2	NY/NJ	40.67	66.01	70.59	77.44	84.95
3	Mid Atlantic	35.31	58.33	64.80	71.21	78.23
4	South Atlantic	39.14	57.61	62.60	69.20	76.50
5	Midwest	38.26	34.27	39.54	44.04	49.05
6	Southwest	39.67	34.80	39.71	43.98	49.11
7	Central	34.46	28.93	32.86	36.24	40.87
8	North Central	26.20	20.81	21.49	22.51	24.03
9	West	39.70	55.65	59.34	65.03	71.27
10	Northwest	37.56	44.71	46.47	51.07	56.12
	National	37.37	47.24	51.57	56.69	62.51
			In 1980 Dollars Per Million Btu			
1	New England	--	3.89	4.27	4.71	5.18
2	NY/NJ	1.55	3.60	3.85	4.23	4.64
3	Mid Atlantic	1.35	3.18	3.54	3.89	4.27
4	South Atlantic	1.49	3.14	3.42	3.78	4.18
5	Midwest	1.46	1.87	2.16	2.40	2.68
6	Southwest	1.51	1.90	2.17	2.40	2.68
7	Central	1.32	1.58	1.79	1.98	2.23
8	North Central	1.00	1.14	1.17	1.23	1.31
9	West	1.52	3.04	3.24	3.55	3.89
10	Northwest	1.43	2.44	2.54	2.79	3.06
	National	1.43	2.58	2.81	3.09	3.41

*U.S. Bureau of the Census, *1980 Annual Survey of Manufacturers*, "Fuels and Electric Energy Consumed," M80(AS)-4.2, Table 3. 1980 regional totals are for all grades and types of coal consumed, not just high-sulfur bituminous.

reasonable assumptions with respect to transportation charges for western coal. Specifically, delivered prices for low-sulfur subbituminous coal have been altered substantially in regions 5, 6, and 7 on the basis of lower transportation charges. The price forecasts given in Table 76 for these regions are based on stable minemouth prices and real increases in transportation charges of 2-1/2 percent per year.

Marginal changes from ARC price forecasts have also been made in DOE regions 3, 4, and 7 for both high-sulfur bituminous and low-sulfur bituminous coals. Prices have been raised in regions 3 and 7 and lowered in region 4 to more closely approximate DRI projections for these regions. It should also be pointed out that the year 2000 forecasts have been manufactured since the ARC forecasts only go out to 1995. The figures for 2000 were obtained by simply applying the same percentage increase assumed for the period 1990-1995 to the 1995-2000 period.

As shown in Tables 74 through 76, considerable price variation among the regions is predicted. Moreover, it should be stated that the three varieties of coal listed do not begin to represent all the variants that will be burned; therefore, the numbers given do not represent regional price averages. Actual prices will be determined through a complex mix of other factors besides those already mentioned. These include:[68]

- The specific coal market involved
  - Geographic (30 to 60 supply regions)
  - Product definition (the various qualities of coal--40 to 50 possible coal types)
  - Transportation modes
- Types of transaction
  - Short-term commitment
  - Long-term commitment
- Type of customer
  - Utilities with large, continuous coal needs
  - Industries with sporadic and smaller coal needs
- Time when the transaction was made (compared to when it was shipped)
- Producer/purchaser relationship
  - Financing
  - Administration

Electricity Prices

Tables 77 and 78 give regional forecasts for electricity; these are based neither on ARC nor DRI national totals. ARC prices appear too low. High-capacity reserve margins and aggressive utility load management programs are likely to restrict utility investment in coal and nuclear facilities (which ARC assumed will substitute for high-priced oil and gas). For similar reasons, it is difficult to believe DRI projections of 1 percent and 0 percent annual price hikes for the industrial and commercial sectors, respectively, during the 1985-1995 time period. Therefore, national totals found in Tables 77 and 78 have been obtained by extending current (1980-1982) annual growth rates in prices out to 1985 (roughly 4.2 percent per year in the commercial sector and 7.6 percent per year in the industrial sector), and by increasing prices at a rate of 2 percent per year thereafter. This approximates the growth rate projected by NEPP over 1985-1995.

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[68]Fossil Energy Division, *A Review of Coal Supply Models*, DOE/FE-0031 (DOE, October 1982).

Table 77

Expected Industrial Electricity Prices by Region

	Region	1980	1985	1990	1995	2000
		Cents Per kWh (In 1980 Dollars)				
1	New England	5.11	6.88	7.64	8.61	9.51
2	NY/NJ	4.38	5.60	5.98	6.77	7.48
3	Mid Atlantic	3.85	4.42	4.94	5.74	6.34
4	South Atlantic	3.18	4.38	5.04	5.82	6.47
5	Midwest	3.52	4.59	5.04	5.57	6.15
6	Southwest	2.00	4.71	6.24	6.77	7.48
7	Central	3.28	4.75	4.99	5.34	5.90
8	North Central	2.26	2.50	2.39	2.12	2.35
9	West	4.78	6.64	7.49	8.09	8.94
10	Northwest	1.04	1.79	2.13	2.98	3.30
	National	3.41	4.71	5.20	5.74	6.34
		In 1980 Dollars Per Million Btu				
1	New England	14.97	20.19	22.41	25.26	27.90
2	NY/NJ	12.83	16.43	17.54	19.68	21.95
3	Mid Atlantic	11.28	12.97	14.49	16.84	18.60
4	South Atlantic	9.32	12.85	14.79	17.08	18.98
5	Midwest	10.31	13.47	14.79	16.34	18.04
6	Southwest	5.86	13.82	18.31	19.86	21.95
7	Central	9.61	13.94	14.64	15.67	17.31
8	North Central	6.62	7.33	7.01	6.22	6.89
9	West	14.00	19.48	21.97	23.74	26.23
10	Northwest	3.05	5.25	6.26	8.74	9.68
	National	10.00	13.82	15.26	16.84	18.60

Table 78

Expected Commercial Electricity Prices by Region

	Region	1980	1985	1990	1995	2000
		Cents Per kWh (In 1980 Dollars)				
1	New England	6.53	8.06	8.97	10.06	11.10
2	NY/NJ	7.56	8.06	8.69	9.68	10.68
3	Mid Atlantic	5.26	5.81	6.49	7.39	8.16
4	South Atlantic	4.47	5.44	6.21	7.16	7.90
5	Midwest	5.11	5.94	6.55	7.24	7.99
6	Southwest	2.92	6.25	7.94	8.07	8.91
7	Central	4.42	6.31	6.07	6.55	7.23
8	North Central	3.92	3.87	3.86	3.81	4.21
9	West	6.19	7.12	8.00	8.76	9.67
10	Northwest	2.38	2.93	3.38	4.34	4.79
	National	5.09	6.25	6.90	7.62	8.41
		In 1980 Dollars Per Million Btu				
1	New England	19.13	23.65	26.32	29.52	32.58
2	NY/NJ	22.15	23.65	25.50	28.40	31.33
3	Mid Atlantic	15.41	17.05	19.04	21.68	23.94
4	South Atlantic	13.10	15.96	18.22	21.00	23.18
5	Midwest	14.97	17.43	19.22	21.24	23.44
6	Southwest	8.55	18.33	23.29	23.68	26.14
7	Central	12.95	18.51	17.81	19.22	21.21
8	North Central	11.49	11.35	11.33	11.18	12.35
9	West	18.14	20.69	23.47	25.70	28.37
10	Northwest	6.97	8.60	9.92	12.73	14.05
	National	14.93	18.33	20.24	22.36	24.67

Regional totals are derived by assessing how much ARC regional figures deviate from the ARC national total, and then simply calibrating these deviations to the national figures obtained, as described above. The reasonableness of the ARC regional variations was carefully assessed, and changes were made in regions 6 and 8 for the reasons described on p 93.

The existing large range in electricity prices among regions is expected to continue well into the future. Prices in several regions will remain more than twice those found in two low-cost regions: the Northwest and North Central. In fact, electricity prices in the North Central region are expected to remain stable throughout the 1980-2000 period due to the availability of low-cost western coal. Electricity prices in the Northwest will remain far below average due to continued heavy reliance on hydroelectric power; however, with the introduction of coal and nuclear power plants in the region throughout the 20-year period, prices will begin to move up.

Major changes are likely to take place in only one other region over this time period--the Southwest. The forecast is for electricity prices in this region to increase at close to 6 percent per year between 1980 and 2000. Regions forecasted to have continued relatively high electricity prices are the Northeast, New York/New Jersey, and West regions.

Prices of Less Conventional Fuels

Wood. The price of wood is very sensitive to distance from the source, so that even a subregional analysis would not adequately account for local conditions. Table 79 shows a preliminary estimate for localities within the named regions that are no more than 100 miles from the source.[63] These prices were not expected to change appreciably through 2000 reflecting a judgment that wood would not become a major energy source. However, for the economic analysis, the assumption is suggested that where wood is available as a fuel, its price will rise to match the cost of coal for comparable output energy (equal $/MBtu output). For example, the price of wood will rise to about 95 percent that of coal for a packaged watertube boiler.

Waste. The cost of waste as fuel has two components: the cost of processing (less the value of any recovered materials) and a credit representing the savings resulting from avoiding conventional disposal. The latter component is probably more sensitive to location than is any other fuel price, even varying within a metropolitan area as one moves from the core to the suburbs. Assuming a representative disposal cost of $6 per ton of waste, DRDF would cost $14 per ton of waste processed or $1.60 per million Btu. Waste with minimal processing (removal of large pieces and ferrous materials) would carry a credit larger than the processing cost, with a net credit of $2 per ton of waste and a fuel credit of $.20 per million Btu (5000 Btu per pound). These prices are assumed to apply nationwide and to be constant through the year 2000.

Coal-Liquid Mixtures. There are also two cost components to coal-liquid mixtures: the component fuel costs and the cost of mixing and stabilizing. Prices for coal and oil are given in earlier tables. The cost of processing COM is assumed to be $1.90 per million Btu in 1985, dropping to $1.50 in 1990, to $1.30 by 1995, and to $1.00 by 2000 as the mixing and transporting technology and infrastructure mature. Suppose we have a 50-50 mixture (by weight) of low-sulfur bituminous coal (Table 75) with residual fuel oil (Table 76) and add the processing costs. If the coal and oil have 12 and 19 kBtu

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[63] I. Spiewak, et al.

per pound, respectively, the resulting prices are as shown in Table 80. According to the table, COM would not be competitive with residual fuel oil until after 1990. Similarly, the mixing of coal-water slurries is assumed to cost \$.50 per million Btu in 1985 and 1990, \$.45 in 1995, and \$.40 in 2000.

Test of Sensitivity to Fuels Assumptions

To test the sensitivity of these results to the fuel price assumptions used for this report, the results presented in Chapters 7 and 8 were compared with those obtained using other fuels databases. The fuels databases compared included the low-, mid-, and high-priced cases for ARC and NEPP (national prices, see Figure 4), and in each of the 10 DOE regions, the prices of a study by Hagler Bailly.[70] In the latter study, the test boiler houses had capacity requirements of 40 and 100 MBtu/hr (CF=0.6), and the rankings were essentially the same across all of these databases. Thus, the fuels alternatives rankings do not change significantly with the other databases.

Table 79

Expected Wood Prices by Region, 1980-2000

(1980 Dollars)

Region	Price Per Dry Ton	Price Per Million Btu
1 thru 5	37	2.1
6 thru 8	Not available	Not available
9 and 10	48	2.7

Table 80

Expected Coal-Oil Mixture Prices by Region
(50-50 Mixture By Weight, in 1980 Dollars Per Million Btu)

Region	1985	1990	1995	2000
1 New England	5.54	5.87	6.40	6.93
2 NY/NJ	5.51	5.81	6.33	6.86
3 Mid Atlantic	5.30	5.63	6.17	6.71
4 South Atlantic	5.13	5.43	5.97	6.51
5 Midwest	5.15	5.46	5.97	6.49
6 Southwest	5.02	5.33	5.93	6.55
7 Central	4.84	5.17	5.72	6.27
8 North Central	4.72	5.03	5.49	5.95
9 West	4.82	5.20	5.73	6.26
10 Northwest	4.89	5.21	5.79	6.45
National	5.16	5.48	6.02	6.56

[70] *Regional Fund Availability and Price Projections through 2000*, HBC Report 82-472-3 (Hagler, Bailly and Company, September 1982).

7 METHODOLOGY AND RESULTS

The analysis presented here is intended to be general in nature, with the fuels prices and analysis techniques developed from several sources. It is essential that current policy be determined, both for fuel price calculations and life-cycle cost analysis procedures, in cases where a more detailed study is required to develop an actual project (see Chapter 8). As noted in the section *Test of Sensitivity to Fuels Assumptions*, fuels selection rankings are essentially the same across a variety of databases obtained from both government and private sources. Thus, although current policy is not followed exactly, these study results are quite valid in developing background data. For illustration, options are considered here that are against current policy (for example, large gas/oil boilers).

Analysis Procedure

Economic Analysis

The method of LCC analysis is well established in textbooks[71] and government publications.[72] The basic LCC concept is that to decide among several alternatives, both future and present costs are brought together in terms of their present worths. The present worth of a future cost is established by discounting it back to its worth in the base year where the first costs will be incurred. Other important related terms include "analysis period," "constant dollars," "discount rate," "economic life," "first cost," "operating cost," and "present worth factor." These are defined in the references cited above. Stated simply,

$$LCC = CC + O\&M + FL$$

where: CC = net capital investment costs (first cost, replacement cost, and possibly salvage value)

O&M = nonfuel operation and maintenance costs (which recur periodically)

FL = fuel costs

(all costs are in life-cycle, present-worth dollars).

The present analysis used a 1985 base year, a 25-year analysis period, constant (1980) dollars, a 10 percent discount rate, and equipment economic lives that ranged from 15 to 40 years, as shown in Table 1. Technologies with lives of less than 25 years were replaced with the same technology at the end of their economic lives. Any life remaining at the 25-year point (after linear depreciation) was credited as an artificial salvage value. This is somewhat equivalent to employing what economists call the "chain rule." Existing technologies were assigned a remaining life of 15 years, after which they

[71] D. G. Newman, "Present Worth Analysis," Chapter 5 in *Engineering Economic Analysis*, revised ed. (Engineering Press, 1980).

[72] R. T. Ruegg, *Life-Cycle Costing Manual for the Federal Energy Management Programs*, NBS Handbook 135 (National Bureau of Standards, 1980).

were also to be replaced with the same technology used at present. Thus, no attempt was made to select a better replacement at the 15-year expiration point.

Implementation of Fuels Price Projections

For the life-cycle analysis of a given fuel and technology, the present worth of the fuel expenditures is needed. Given the boiler efficiency, energy requirement, and fuel prices, the present worth of the fuel costs is required. To find this, modified uniform present-worth factors (UPW*) were derived from fuel price forecasts and multiplied by the base year prices. The resulting present worths were the required result.

A set of fuel price projections was presented in Tables 70 through 80. These are of a consistent and general nature, and form a basis for the next steps. Twelve fuels were determined to be sufficient for the analysis to fully exercise the technology options. Each fuel is shown in Table 81 together with a range of prices across the 10 DOE regions. These prices are study projections for input energy, as derived below.

The prices for coal in Table 81 are derived from Tables 74 and 75. Low-priced coal costs roughly $40 per short ton and uses the prices for high-sulfur bituminous coal given in Table 74. Mid-priced coal costs roughly $60 per ton, and is found by adding $12 per ton to the low-sulfur bituminous coal given in Table 75. Premium coal costs roughly $80 per ton, and is found by adding 80 percent to Table 75. It is a washed, double-screened, low-sulfur coal.

Although the Army is often classed with commercial users, it purchases natural gas in larger quantities. Hence, industrial natural gas prices are taken from Table 72.

Another oil crisis is likely to occur in the next 10 to 20 years, resulting in an increase in the present worth of fuel oil costs by 20 to 30 percent, and the present slump in oil prices is likely to be a temporary respite (1986). The forecasts presented in Tables 70 and 71 do not allow effects such as a supply disruption, and those forecasts have been increased by a conservative 10 percent. The price for residual oil is based on Table 70 and that for distillate on Table 71.

The prices of Table 80 were used for coal-oil mixtures. This is a 50-50 mixture (by weight) of low-sulfur bituminous coal (Table 75) with residual fuel oil (Table 70). A processing cost has been added, but there is no allowance for increases in the oil price following a crisis. Coal-water slurry prices were also derived from the low-sulfur bituminous coal of Table 75 by adding $12 per ton, plus an additional slurry mixing cost of $.50, $.50, $.45 and $.40, per MBtu for 1985, 1990, 1995, and 2000, respectively. For the same reason as for natural gas, electricity is taken at the industrial rates of Table 77. Wood is priced on the assumption that where it is available, its price will rise to match the cost of coal for comparable output energy. Waste is priced at a net savings of $0.20 per MBtu, and DRDF at a net cost of $1.60 per MBtu.

Because detailed forecasts are substantially less meaningful beyond the year 2000, a simplified procedure was used to extend the price estimates to 2005 and 2010. A uniform slope was applied to the prices for all DOE regions for a given fuel, as shown in Table 82. Electricity, gas, and oil were assigned an increase of $0.22 per year (per MBtu), and other fuels were assigned lesser increases, which is consistent with their forecast behavior for earlier years. The exact magnitude of these estimates is not too important, since the present worth of a dollar spent in 2010 is only nine cents in 1985.

Table 81

Fuels Used in Ranking Procedure

Fuel Cost Range*	Low	High
Low-priced coal	1.31	2.02
Mid-priced coal	1.96	3.09
Premium coal	2.36	4.39
Natural gas	3.33	5.33
Residual oil	4.02	4.90
Distillate oil	6.15	6.88
Coal-oil mixture	4.72	5.54
Coal-water slurry	2.46	3.59
Electricity	5.25	20.19
Wood	1.86	2.93
Waste	-.20	-.20
DRDF	2.80	2.80

*$/MBtu input, 1985 costs, 1980 dollars. These costs are the 1985 points on the study projections.

Table 82

Extrapolation Beyond the Year 2000

Fuel	Slope*
Low-priced coal	0.05
Mid-priced coal	0.05
Premium coal	0.05
Natural gas	0.22
Residual oil	0.22
Distillate oil	0.22
Coal-oil mixture	0.22
Coal-water slurry	0.22
Electricity	0.22
Wood	0.05
Waste	0.00
DRDF	0.05

*$/MBtu per year, 1980 dollars.

This gave a price for each fuel for each 5-year point from 1985 through 2010. Table 83 shows some of the results. Tabulated are the price forecast, for each 5-year point, for each DOE region (see Figure 2). The national prices (NAT) represent total dollars divided by total MBtu for the year. All prices are in 1980 dollars, and have been developed as described above.

The next step is to interpolate linearly between the 5-year numbers to obtain a fuel price for each year from 1985 to 2009. A modified uniform present-worth factor UPW* (pronounced U-P-W-Star) is obtained from these yearly prices by the formula

$$UPW^* = \frac{1}{C_1} \sum_{j=1}^{n} \frac{C_j}{(1+d)^j},$$

where: C_j = cost of one MBtu of fuel in year j

d = discount rate

n = analysis period.

Table 84 shows the regional UPW*s (for d = 0.10 and n = 25).

The year 1985 was selected as the base year for this analysis, since it represents the first year of the forecast. Base-year fuel prices (Table 85) were each multiplied by the corresponding UPW* (Table 84) to obtain a 25-year present worth for one MBtu/yr for each fuel and DOE region. Table 86 shows the results for 25-year analysis period, with a base year of 1985 and a 10 percent discount rate. These are the numbers which, when multiplied by the number of input MBtu/yr, give the present worth of the fuel cost for the option under analysis.

Results

This section presents the results of the fuels ranking process. To prepare the recommendations, several hundred analyses were completed covering the 10 DOE regions, output capacities that ranged up to 250 MBtu/hr, and annual capacity use factors (CFs) from 0.1 to 0.8. Each analysis ranked the applicable technologies (and hence, the fuels) in order of the lowest LCC. Tables are presented as examples of the fuels ranking process. The tables include results selected from analyses of DOE Region 4, with CFs of 0.2 and 0.6. The fuels ranking in Region 4 is typical of all the regions, and the regional numerical results are more interesting than the national averages. A CF of 0.2 is more typical of smaller units and of many existing Army boilers. It tends to emphasize the impact of the capital costs first costs (FCs), of new equipment, rather than that of the fuel costs. A CF of 0.6 tends to spread out the numerical results between fuels, and is reasonably representative of a well-used boiler. New construction will tend to have higher CFs, in the face of limited capital availability. Certain technologies which illustrate the various alternative fuels options have been selected for inclusion in the following tables. Generally, several technologies are shown for each class of fuel to illustrate some of the alternatives available to the fuels ranking process.

Three prices for different types of coal were included in this study. These prices were distributed among the technology options to test the impact of a range of fuel price options on the LCCs of coal plants. For example, low-priced coal (coal-lo) was assigned to large field-erected pulverized coal (PC) units with scrubbers; mid-priced coal (coal-

Table 83

Fuel Prices, 1985-2010*

Region:	1	2	3	4	5	6	7	8	9	10	NAT
A: Low-Priced Coal											
1985	2.02	1.79	1.62	1.89	1.59	1.75	1.58	1.31	1.75	1.99	1.60
1990	2.16	1.91	1.79	2.07	1.74	1.88	1.81	1.43	1.99	2.19	1.72
1995	2.32	2.04	1.98	2.23	1.81	2.24	1.94	1.51	2.19	2.39	1.88
2000	2.50	2.19	2.18	2.41	1.95	2.52	2.09	1.60	2.40	2.60	2.04
2005	2.75	2.44	2.43	2.66	2.20	2.77	2.34	1.85	2.65	2.85	2.29
2010	3.00	2.69	2.68	2.91	2.45	3.02	2.59	2.10	2.90	3.10	2.54
B: Mid-Priced Coal											
1985	3.09	2.94	2.76	2.87	2.75	2.43	2.44	1.96	2.42	2.51	2.62
1990	3.29	3.07	2.97	3.01	2.90	2.59	2.66	2.13	2.76	2.68	2.81
1995	3.52	3.27	3.23	3.26	3.08	2.98	2.94	2.17	2.97	3.04	3.05
2000	3.75	3.49	3.48	3.52	3.28	3.44	3.20	2.21	3.21	3.59	3.32
2005	4.00	3.74	3.73	3.77	3.53	3.69	3.45	2.46	3.46	3.84	3.57
2010	4.25	3.99	3.98	4.02	3.78	3.94	3.70	2.71	3.71	4.09	3.82
C: Premium Coal											
1985	4.39	4.12	3.80	4.00	3.78	3.20	3.22	2.36	3.19	3.35	3.55
1990	4.75	4.36	4.18	4.25	4.05	3.49	3.62	2.66	3.80	3.65	3.89
1995	5.17	4.72	4.64	4.70	4.37	4.19	4.12	2.74	4.18	4.30	4.32
2000	5.58	5.11	5.09	5.17	4.73	5.02	4.59	2.81	4.61	5.29	4.81
2005	5.83	5.36	5.34	5.42	4.98	5.27	4.84	3.06	4.86	5.54	5.06
2010	6.08	5.61	5.59	5.67	5.23	5.52	5.09	3.31	5.11	5.79	5.31

*$/MBtu, 1980 dollars.

Table 83 (Cont'd)

Region:	1	2	3	4	5	6	7	8	9	10	NAT
D: Coal-Water Slurry											
1985	3.59	3.44	3.26	3.37	3.25	2.93	2.94	2.46	2.92	3.01	3.12
1990	3.79	3.57	3.47	3.51	3.40	3.09	3.16	2.63	3.26	3.18	3.31
1995	3.97	3.72	3.68	3.71	3.53	3.43	3.39	2.62	3.42	3.49	3.50
2000	4.15	3.89	3.88	3.92	3.68	3.84	3.60	2.61	3.61	3.99	3.72
2005	5.25	4.99	4.98	5.02	4.78	4.94	4.70	3.71	4.71	5.09	4.82
2010	6.35	6.09	6.08	6.12	5.88	6.04	5.80	4.81	5.81	6.19	5.92
E: Natural Gas											
1985	5.33	4.61	4.53	4.28	4.43	3.33	3.83	3.98	4.22	4.32	3.87
1990	6.33	5.61	5.53	5.28	5.43	4.33	4.83	4.98	5.22	5.32	4.87
1995	7.33	6.61	6.53	6.28	6.43	5.33	5.83	5.98	6.22	6.32	5.87
2000	8.48	7.76	7.68	7.43	7.58	6.48	6.98	7.13	7.37	7.47	7.02
2005	9.58	8.86	8.78	8.53	8.68	7.58	8.08	8.23	8.47	8.57	8.12
2010	10.68	9.96	9.88	9.63	9.78	8.68	9.18	9.33	9.57	9.67	9.22
F: Residual Oil											
1985	4.84	4.90	4.63	4.25	4.38	4.37	4.03	4.15	4.02	4.08	4.48
1990	6.01	6.06	5.80	5.41	5.54	5.53	5.19	5.31	5.18	5.25	5.64
1995	7.16	7.22	6.95	6.57	6.70	6.69	6.35	6.47	6.34	6.40	6.80
2000	8.49	8.55	8.28	7.90	8.03	8.02	7.68	7.80	7.67	7.73	8.13
2005	9.59	9.65	9.38	9.00	9.13	9.12	8.78	8.90	8.77	8.83	9.23
2010	10.69	10.75	10.48	10.10	10.23	10.22	9.88	10.00	9.87	9.93	10.33

Table 83 (Cont'd)

Region:	1	2	3	4	5	6	7	8	9	10	NAT
G: Wood											
1985	2.93	2.78	2.61	2.72	2.60	2.30	2.31	1.86	2.29	2.38	2.48
1990	3.11	2.91	2.81	2.85	2.75	2.45	2.52	2.02	2.61	2.54	2.66
1995	3.33	3.10	3.06	3.09	2.92	2.82	2.78	2.05	2.81	2.88	2.89
2000	3.55	3.30	3.29	3.33	3.11	3.26	3.03	2.09	3.04	3.40	3.14
2005	3.80	3.55	3.54	3.58	3.36	3.51	3.28	2.34	3.29	3.65	3.39
2010	4.05	3.80	3.79	3.83	3.61	3.76	3.53	2.59	3.54	3.90	3.64
H: Distillate Oil											
1985	6.85	6.88	6.75	6.88	6.24	6.17	6.15	6.48	6.25	6.25	6.40
1990	8.51	8.54	8.42	8.54	7.90	7.83	7.81	8.14	7.91	7.91	8.06
1995	10.18	10.20	10.08	10.20	9.56	9.49	9.47	9.80	9.57	9.57	9.72
2000	12.07	12.09	11.97	12.09	11.45	11.39	11.36	11.69	11.46	11.46	11.62
2005	13.17	13.19	13.07	13.19	12.55	12.49	12.46	12.79	12.56	12.56	12.72
2010	14.27	14.29	14.17	14.29	13.65	13.53	13.56	13.89	13.66	13.66	13.82
I: Electricity											
1985	20.19	16.43	12.97	12.85	13.47	13.82	13.94	7.33	19.48	5.25	13.82
1990	22.41	17.54	14.49	14.79	14.79	18.31	14.64	7.01	21.97	6.25	15.26
1995	25.26	19.68	16.84	17.08	16.34	19.86	15.67	6.22	23.74	8.74	16.84
2000	27.90	21.95	18.60	18.98	18.04	21.95	17.31	6.89	26.23	9.68	18.60
2005	29.00	23.05	19.70	20.08	19.14	23.05	18.41	7.99	27.33	10.78	19.70
2010	30.10	24.15	20.80	21.18	20.24	24.15	19.51	9.09	28.43	11.88	20.80

Table 84

Regional UPW*s‡,‡‡

Region

1	2	3	4	5	6	7	8	9	10	NAT	FUEL
10.15	10.12	10.64	10.37	10.22	10.83	10.72	10.26	10.82	10.48	10.33	Coal (Low)
10.03	9.87	10.22	10.01	9.93	10.61	10.44	9.91	10.65	10.62	10.22	Coal (Mid)
10.23	10.04	10.52	10.23	10.14	11.11	10.86	10.23	11.16	11.09	10.53	Coal (Prem)
11.69	12.10	12.16	12.34	12.23	13.27	12.72	12.58	12.38	12.31	12.68	Nat Gas
12.38	12.35	12.53	12.85	12.73	12.74	13.05	12.94	13.06	13.00	12.65	Residual
12.34	12.33	12.38	12.33	12.66	12.70	12.71	12.52	12.65	12.65	12.57	Distillate
10.24	10.21	10.31	10.31	10.29	10.43	10.44	10.33	10.49	10.48	10.33	Coal-Oil
10.01	9.94	10.24	10.06	10.00	10.57	10.42	10.00	10.60	10.58	10.24	Coal-Water
10.66	10.37	10.91	11.15	10.51	12.05	10.01	8.73	10.59	12.73	10.55	Electricity
10.01	9.89	10.23	10.01	9.96	10.62	10.44	9.90	10.66	10.62	10.22	Wood
9.08	9.08	9.08	9.08	9.08	9.08	9.08	9.08	9.08	9.08	9.08	Waste
9.17	9.17	9.17	9.17	9.17	9.17	9.17	9.17	9.17	9.17	9.17	DRDF

‡UPW* (pronounced U-P-W-Star) is modified present worth factor.
‡‡25-year analysis period, 10 percent discount rate.

Table 85

Regional Base-Year Fuel Prices*

Region

1	2	3	4	5	6	7	8	9	10	NAT	FUEL
2.02	1.79	1.62	1.89	1.59	1.75	1.58	1.31	1.75	1.99	1.60	Coal (Low)
3.09	2.94	2.76	2.87	2.75	2.43	2.44	1.96	2.42	2.51	2.62	Coal (Mid)
4.39	4.12	3.80	4.00	3.78	3.20	3.22	2.36	3.19	3.35	3.55	Coal (Prem)
5.33	4.61	4.53	4.28	4.43	3.33	3.83	3.98	4.22	4.32	3.87	Nat Gas
4.84	4.90	4.63	4.25	4.38	4.37	4.03	4.15	4.02	4.08	4.48	Residual
6.85	6.88	6.75	6.88	6.24	6.17	6.15	6.48	6.25	6.25	6.40	Distillate
5.54	5.51	5.30	5.13	5.15	5.02	4.84	4.72	4.82	4.89	5.16	Coal-Tar
3.59	3.44	3.26	3.37	3.25	2.93	2.94	2.46	2.92	3.01	3.12	Coal-Water
20.19	16.43	12.97	12.85	13.47	13.82	13.94	7.33	19.48	5.25	13.82	Electricity
2.93	2.78	2.61	2.72	2.60	2.30	2.31	1.86	2.29	2.38	2.48	Wood
-.20	-.20	-.20	-.20	-.20	-.20	-.20	-.20	-.20	-.20	-.20	Waste
2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	DRDF

*$/MBtu, 1980 dollars, 1985 study projections.

Table 86

Regional 25-Year Present Worths, 1985-2009*

Region											
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**NAT**	**FUEL**
20.51	18.11	17.23	19.59	16.25	18.95	16.94	13.45	18.93	20.85	16.52	Coal (Low)
30.98	29.02	28.21	28.72	27.32	25.79	25.47	19.43	25.78	26.65	26.77	Coal (Mid)
44.93	41.40	39.94	40.86	38.33	35.59	35.00	24.13	35.56	37.13	37.35	Coal (Prem)
62.33	55.79	55.07	52.80	54.16	44.18	48.71	50.08	52.25	53.16	49.08	Nat Gas
59.94	60.43	58.04	54.54	55.74	55.64	52.55	53.65	52.45	53.05	56.64	Residual
84.54	84.74	83.64	84.74	78.95	78.35	78.15	81.15	79.05	79.05	80.45	Distillate
56.76	56.25	54.63	52.89	52.99	52.35	50.52	48.77	50.55	51.24	53.30	Coal-Oil
36 17	34.20	33.39	33.90	32.50	30.97	30.65	24.61	30.96	31.83	31.95	Coal-Water
215.32	170.37	141.47	143.23	141.53	166.59	139.58	63.96	206.29	66.82	145.741	Electricity
29.34	27.49	26.70	27.22	25.90	24.43	24.12	18.42	24.41	25.27	25.35	Wood
-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	-1.82	Waste
25.69	25.69	25.69	25.69	25.69	25.69	25.69	25.69	25.69	25.69	25.69	DRDF

$/MBtu, 10 percent discount rate, 1980 dollars. This table results from multiplying each fuel price of Table 85 by the corresponding UPW of Table 84.

mid) to those PC units without scrubbers, as well as to large field-erected stoker boilers with scrubbers; and premium or high-priced coal (coal-hi) (compliance coal) to large stoker boilers without scrubbers. This ensured that the ranking of a variety of coal fuels options was considered. High-priced (double-screened) coal was also assigned to small coal furnaces.

Examples of Alternatives for Large Boilers and Boiler Plants

The first example (Tables 87 and 88) compares a number of technology alternatives that provide an output capacity of 20 MBtu/hr. An existing packaged firetube boiler (Technology 20) may be burning gas, oil, or coal. The boiler costs are illustrated at annual capacity use factors of 0.2 and 0.6, and the location is in DOE Region 4. Both the capital or FC, and the LCC are presented in millions of 1980 dollars to compare the alternatives. There is relatively little difference in LCC among these current process options for a given CF. As long as the boiler is in good condition, it is reasonable to continue with the present process, provided the fuel is not distillate oil. (Where the existing fuel is distillate, conversion to natural gas or to heavier oil should be considered. Heavier oil presents storage and plumbing problems, and is not presently typical for smaller boilers.) Where possible, there should be dual fuel capability for increased protection against fuel shortages or fuel price fluctuations. ("Dual fuel" does not mean the capability for burning several different grades of oil.) When the boiler requires major repairs, such as extensive retubing, the purchase of a new boiler may be better than a major overhaul. This conclusion derives from the assumption that a new boiler has higher efficiency and lower maintenance costs, in comparison with a similar existing boiler.

When the purchase of a new 20 MBtu/hr boiler is considered, low first cost, low predicted maintenance and repair costs, and dual fuel capability will all be factors in the selection process. Here, the best choice for a new boiler is a packaged gas/oil firetube boiler, with the capability of burning both natural gas and residual oil. This choice has both low first cost and low life cycle cost. However, for the conditions analyzed, a number of other more expensive alternatives are available. Where solid fuel is selected for this output capacity, several different technologies are available, and atmospheric fluidized bed combustion (AFBC) is among the alternatives worth considering. For high annual capacity use (high CF), first costs become less important, and the selection of a lower-cost fuel such as coal is more important for lowering the LCC. That is, for full use or base-loading with high CF, the present worth of the fuel costs has a greater effect on the LCC, while for low use the capital or first cost has greater effect on the LCC.

Tables 89 and 90 illustrate the urgency for reducing dependence on distillate fuel oil. The tables show several gas/oil alternatives to an existing 40 MBtu/hr plant that now burns distillate. The plant has two 20 MBtu/hr packaged firetube boilers; a good fuel choice would be to achieve dual fuel capability for selecting between natural gas and residual oil. If the existing boilers are in good condition, the developing coal-water technologies may, in the future, provide a cost-effective alternative, but it is better to convert to natural gas or residual oil now. The LCC for new boilers with relatively low first cost may be about the same as that for conversion to the same fuel in existing boilers (Table 90). Before implementing one of the solid fuel alternatives (coal, wood, or waste), a carefully detailed analysis should be completed, but these are also among the opportunities for LCC savings, in comparison with the present use of distillate.

Tables 91 and 92 present additional alternatives for a similar 40 MBtu/hr gas/oil plant. Here, distillate fuel is not an issue, and the plant costs are not unreasonable, as it is operated now. Some savings may be possible through tune-ups, but as long as the

Table 87

Alternatives for 20-MBtu/Hr Output Capacity (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Gas	Packaged gas/oil firetube (20***)	0.0	6.2
Resid	Packaged gas/oil firetube (20)	0.0	6.3
Coal-hi	Packaged coal firetube (10)	0.0	7.7
Dist	Packaged gas/oil firetube (20)	0.0	7.7
	New Boiler		
Gas	Packaged gas/oil firetube (20)	0.5	6.4
Resid	Packaged gas/oil firetube (20)	0.5	6.5
Waste	Heat-recovery incinerator (18)	3.2	7.6
Coal-hi	Packaged coal firetube (10)	1.7	9.3
Coal-hi	Packaged coal stoker (52)	2.0	9.4
Coal-mid	Packaged coal AFBC (14)	2.3	9.6
Wood	Packaged wood stoker (11)	2.7	9.8
Wood	Packaged wood AFBC (15)	2.7	9.8

*Existing packaged firetube boiler, 20 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4. FC and LCC in millions of 1980 dollars. Atmospheric fluidized bed combustion is abbreviated AFBC. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal. The price of wood is derived from that of coal-mid.

**It is often possible to convert a firetube boiler to another fuel at a relatively negligible cost. The least expensive fuel should be selected (lowest $/MBtu).

***Shown in parentheses is the Technology No. used to identify the combustion technology alternative in this report (See Table 1).

Table 88

Alternatives for 20-MBtu/Hr Output Capacity (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Gas	Packaged gas/oil firetube (20)	0.0	11.3
Resid	Packaged gas/oil firetube (20)	0.0	11.5
Coal-hi	Packaged coal firetube (10)	0.0	12.1
Dist	Packaged gas/oil firetube (20)	0.0	15.7
	New Boiler		
Gas	Packaged gas/oil firetube (20)	0.5	11.2
Resid	Packaged gas/oil firetube (20)	0.5	11.4
Coal-mid	Packaged coal AFBC (14)	2.3	12.7
Wood	Packaged wood stoker (11)	2.7	12.8
Wood	Packaged wood AFBC (15)	2.7	12.9
Waste	Heat-recovery incinerator (18)	3.2	13.0
Coal-hi	Packaged coal firetube (10)	1.7	13.5
Coal-hi	Packaged coal stoker (52)	2.0	13.5

*Existing packaged firetube boiler, 20 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars.

**It is often possible to convert a firetube boiler to another fuel at a relatively negligible cost. The least expensive fuel should be selected (lowest $/MBtu).

Table 89

Gas/Oil Alternatives to 40-MBtu/Hr Distillate Oil Plant (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Dist	Packaged gas/oil firetube (20) (two)	0.0	13.9
	Conversion or Retrofit**		
Gas	Convert to natural gas	0.0	10.9
Resid	Convert to residual oil	0.0	11.1
	New Boiler(s)		
Gas	Packaged gas/oil watertube (21) (one)	1.0	9.8
Resid	Packaged gas/oil watertube (21) (one)	1.0	10.0
Gas	Packaged gas/oil firetube (20) (two)	0.9	11.3
Resid	Packaged gas/oil firetube (20) (two)	0.9	11.4

*Two existing packaged firetube boilers, 20 MBtu/hr output capacity each, 0.2 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars.

**Fuel should be selected between natural gas and residual oil according to the lowest fuel cost ($/MBtu). Cost of conversion is assumed negligible.

Table 90

Gas/Oil Alternatives to 40-MBtu/Hr Distillate Oil Plant (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Dist	Packaged gas/oil firetube (20) (two)	0.0	29.8
	Conversion or Retrofit**		
Gas	Convert to natural gas	0.0	21.0
Resid	Convert to residual oil	0.0	21.5
	New Boiler(s)***		
Gas	Packaged gas/oil watertube (21) (one)	1.0	19.4
Resid	Packaged gas/oil watertube (21) (one)	1.0	19.8
Gas	Packaged gas/oil firetube (20) (two)	0.9	20.8
Resid	Packaged gas/oil firetube (20) (two)	0.9	21.3

*Two existing packaged firetube boilers, 20 MBtu/hr output capacity each, 0.6 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars.

**Fuel should be selected between natural gas and residual oil according to the lowest fuel cost ($/MBtu). Cost of conversion is assumed negligible.

***Note that the LCC for new boilers may be about the same as that for conversion to the same fuel in existing boilers. A converted boiler is assumed to be less efficient and to have greater operation and maintenance costs. This may offset the FC of a new gas/oil boiler.

Table 91

Alternatives to 40-MBtu/Hr Gas/Oil Plant (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Gas	Packaged gas/oil firetube (20) (two)	0.0	10.9
Resid	Packaged gas/oil firetube (20) (two)	0.0	11.1
	Conversion or Retrofit***		
CWM	Coal-water mix retrofit (39)	2.6	9.0
COM	Coal-oil mix retrofit (37)	1.7	9.1
CWM	Coal-water retrofit with scrubber (40)	3.6	11.6
Coal-lo	Small low-Btu gasification (27)	3.5	14.7
	New Boiler(s)		
Gas	Packaged gas/oil watertube (21)+	1.0	9.8
Resid	Packaged gas/oil watertube (21)+	1.0	10.0
Waste	Heat-recovery incinerator (18)	4.7	10.9
Gas	Packaged gas/oil firetube (20) (two)	0.9	11.3
Resid	Packaged gas/oil firetube (20) (two)	0.9	11.4
Coal-hi	Packaged coal stoker (52)	3.1	14.3
Wood	Packaged wood stoker (11)	3.9	14.4
Wood	Packaged wood AFBC (15)	4.0	14.4

*Two existing packaged firetube boilers, 20 MBtu/hr output capacity each, 0.2 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars.

**Fuel should be selected between natural gas and residual oil according to the lowest present fuel cost ($/MBtu). Cost of switching or conversion is assumed negligible.

***None of these conversions or retrofits is recommended at this time. The costs for CWM/COM options are somewhat speculative, and these technologies do not yet have an established track record.

+This example is about at the 50 MBtu/hr input limit for new gas- or oil-fueled boilers (50 MBtu/hr input x 80 percent efficiency = 40 MBtu/hr output).

Table 92

Alternatives to 40 MBtu/Hr Gas/Oil Plant (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Gas	Packaged gas/oil firetube (20) (two)	0.0	21.0
Resid	Packaged gas/oil firetube (20) (two)	0.0	21.5
	Conversion or Retrofit***		
CWM	Coal-water mix retrofit (39)	2.6	15.2
CWM	Coal-water retrofit with scrubber (40)	3.6	18.4
COM	Coal-oil mix retrofit (37)	1.7	18.5
Coal-lo	Small low-Btu gasification (27)	3.5	19.8
	New Boiler(s)		
Waste	Heat recovery incinerator (18)	4.7	18.6
Gas	Packaged gas/oil watertube (21)+	1.0	19.4
Resid	Packaged gas/oil watertube (21)+	1.0	19.8
Wood	Packaged wood stoker (11)	3.9	20.3
Wood	Packaged wood AFBC (15)	4.0	20.3
Gas	Packaged gas/oil firetube (20) (two)	0.9	20.8
Resid	Packaged gas/oil firetube (20) (two)	0.9	21.3
Coal-hi	Packaged coal stoker (52)	3.1	22.3

*Two existing packaged firetube boilers, 20 MBtu/hr output capacity each, 0.6 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars.

**Fuel should be selected between natural gas and residual oil according to the lowest present fuel cost ($/MBtu). Cost of switching or conversion is assumed negligible.

***None of these conversions or retrofits is recommended at this time. The costs for CWM/COM options are somewhat speculative, and these technologies do not yet have an established track record.

+This example is about at the 50 MBtu/hr input limit for new gas- or oil-fueled boilers (50 MBtu/hr input x 80 percent efficiency = 40 MBtu/hr output).

equipment is functional, the need for change is not urgent. CWM technologies look promising when they have had fuller development. The costs shown are somewhat speculative. COM and coal gasification technologies are not very competitive, in comparison. The gasifier is included for comparison with the other retrofit technologies, but it is the most expensive retrofit, because its low fuel cost is offset by capital and maintenance costs and by overall lower system efficiency. A similar analysis applies to new waste boilers. Waste is given a negative fuel cost to allow for the net savings from landfill and transportation costs (-$0.20 per input MBtu, a net credit of $7.00/ton) and thus appears relatively attractive, but the high capital and maintenance costs suggest its selection only if necessary to solve other problems. The cost of CWM fuel is derived from that of mid-priced coal (coal-mid), and that of COM from coal-mid and residual oil.

This size is about at the limit for new gas/oil boilers, and such a requirement is not an unreasonable one (at CF = 0.6) in light of the LCC ranking and national needs (Table 92). From a purely economic analysis of the tables, the low first costs and easy maintenance of packaged gas/oil boilers make them attractive, even though some solid fuels have comparable LCCs. However, a policy that would require solid fuel for this case is not too bad, provided that there is good use of the equipment and a commitment to a long-term energy requirement that justifies the higher capital expenditure.

Tables 93 and 94 consider solid fuel alternatives to an existing 40 MBtu/hr coal boiler. For the current plant, coal is selected for a reasonable combination of price, availability, and technological compatibility with the existing plant. The lower the fuel cost, the lower the LCC, so if wood is available, it may be a good alternative to coal. Since the capital costs for solid fuel boilers are high, it is best to continue using the current coal boiler where possible, with major overhauls justified as needed. Full use is a key to using technologies with high first cost and low fuel cost, and it will help to hold down the first cost by choosing as small a solid fuel boiler as possible. With a smaller solid fuel boiler base-loaded, it may be possible to handle swing or peak loads with an existing gas/oil boiler. That is, technologies with low first costs are appropriate for swing loads, low use, or short-lived requirements.

Tables 93 and 94 compare conventional and fluidized-bed technologies (AFBC). Results of this study generally show that AFBC is a competitive class of technologies that merits further consideration. When solid-fuel boilers are considered for procurement, the Army should buy a few from among the several different AFBC technologies to get more in-house experience with them. A 40 MBtu/hr output plant would be good for such demonstrations.

For an 80 MBtu/hr output capacity, the same sequence as before is followed: distillate, other gas/oil, and solid fuel technologies. Gas/oil boilers this large are rare at Army installations, and Congress does not permit new boilers of this size. Tables 95 and 96 show an 80 MBtu/hr distillate oil boiler and are included to emphasize the point that distillate is to be avoided if at all possible. Alternatives include conversion, abandonment, and replacement with a new solid-fuel plant. The boiler should be kept like this (on distillate) only for emergencies, or possibly for peak loads.

The alternatives are explored more fully in Tables 97 and 98, where the existing boiler of this example is now assumed to have dual fuel capability for natural gas and residual oil. Although, in this example, gas has an overall lower LCC in comparison with residual oil, it is important to switch between gas and residual since the prices may fluctuate. At certain times, it is likely that residual will be less expensive.

Table 93

Alternatives to Existing 40-MBtu/Hr Coal Boiler (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Coal-lo	Packaged coal stoker (52)	0.0	9.6
Coal-mid	Packaged coal stoker (52)	0.0	10.5
Coal-hi	Packaged coal stoker (52)	0.0	11.7
	Conversion or Retrofit		
Wood	Coal to wood retrofit (34)	0.4	11.1
DRDF	Coal to DRDF retrofit (35)	1.6	13.1
Waste	Coal to waste retrofit (36)	3.7	13.9
	New Boiler(s)		
Gas	Packaged gas/oil watertube (21)***	1.0	9.8
Resid	Packaged gas/oil watertube (21)	1.0	10.0
Waste	Heat-recovery incinerator (18)	4.7	10.9
Coal-hi	Packaged coal stoker (52)	3.1	14.3
Coal-mid	Packaged coal AFBC (14)	3.5	14.3
Wood	Packaged wood stoker (11)	3.9	14.4
Wood	Packaged wood AFBC (15)	4.0	14.4
Coal-hi	Packaged coal stoker with baghouse (9)	3.4	15.1
DRDF	Packaged DRDF stoker (13)	4.4	15.5
DRDF	Packaged DRDF AFBC (17)	4.4	15.5
Coal-hi	Packaged coal firetube (10) (two)	3.1	16.1
Waste	Packaged waste AFBC (16)	6.2	16.7
Waste	Packaged waste stoker (12)	7.7	20.2

*Existing packaged coal stoker boiler (multiple cyclones, no baghouse), 40 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**Coal for the current process is usually selected for a reasonable combination of price, availability, and technological requirements. Among feasible coals, the one with the lowest present fuel cost ($/MBtu) should be selected. The cost of switching or conversion among coals is assumed negligible.

***This is about the 50 MBtu/hr input limit for new gas- or oil-fueled boilers (50 MBtu/hr input x 80 percent efficiency = 40 MBtu/hr output).

Table 94

Alternatives to Existing 40-MBtu/Hr Coal Boiler (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process**		
Coal-lo	Packaged coal stoker (52)	0.0	14.0
Coal-mid	Packaged coal stoker (52)	0.0	16.7
Coal-hi	Packaged coal stoker (52)	0.0	20.3
	Conversion or Retrofit		
Waste	Coal to waste retrofit (36)	3.7	14.9
Wood	Coal to wood retrofit (34)	0.4	17.3
DRDF	Coal to DRDF retrofit (35)	1.6	18.9
	New Boiler(s)		
Waste	Packaged waste AFBC ([illegible])	6.2	17.7
Waste	Heat-recovery incinerator (18)	4.7	18.6
Gas	Packaged gas/oil watertube (21)***	1.0	19.4
Resid	Packaged gas/oil watertube (21)	1.0	19.8
Coal-mid	Packaged coal AFBC (14)	3.5	20.3
Wood	Packaged wood stoker (11)	3.9	20.3
Wood	Packaged wood AFBC (15)	4.0	20.3
DRDF	Packaged DRDF stoker (13)	4.4	21.1
DRDF	Packaged DRDF AFBC (17)	4.4	21.1
Waste	Packaged waste stoker (12)	7.7	21.2
Coal-hi	Packaged coal stoker (52)	3.1	22.3
Coal-hi	Packaged coal stoker with baghouse (9)	3.4	23.3
Coal-hi	Packaged coal firetube (10) (two)	3.1	24.3

*Existing packaged coal stoker boiler (multiple cyclones, no baghouse), 40 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4, FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**Coal for the current process is usually selected for a reasonable combination of price, availability, and technological requirements. Among feasible coals, the one with the lowest present fuel cost ($/MBtu) should be selected. The cost of switching or conversion among coals is assumed negligible.

***This is about the 50 MBtu/hr input limit for new gas- or oil-fueled boilers (50 MBtu/hr input x 80 percent efficiency = 40 MBtu/hr output).

Table 95

Gas/Oil Alternatives to 80-MBtu/Hr Distillate Oil Boiler (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Dist	Packaged gas/oil watertube (21)	0.0	21.3
	Conversion or Retrofit**		
Gas	Convert to natural gas	0.0	15.4
Resid	Convert to residual oil	0.0	15.7
	New Boiler(s)***		
Gas	Packaged gas/oil watertube (21)	1.6	16.1
Resid	Packaged gas/oil watertube (21)	1.6	16.4

*Existing packaged gas/oil watertube boiler, 80 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4. Gas/oil boilers this large are rare at Army installations. FC and LCC in millions of 1980 dollars.

**Cost of conversion is assumed negligible. The assumptions which lead to the large LCC difference between conversions and new boilers may not be fully realistic.

***Congress does not permit new gas/oil boilers of this size. They are included here for comparison.

Table 96

Gas/Oil Alternatives to 80-MBtu/Hr Distillate Oil Boiler (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Dist	Packaged gas/oil watertube (21)	0.0	52.9
	Conversion or Retrofit**		
Gas	Convert to natural gas	0.0	35.3
Resid	Convert to residual oil	0.0	36.2
	New Boiler(s)***		
Gas	Packaged gas/oil watertube (21)	1.6	35.0
Resid	Packaged gas/oil watertube (21)	1.6	35.9

*Existing packaged gas/oil watertube boiler, 80 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4. Gas/oil boilers this large are rare at Army installations. FC and LCC in millions of 1980 dollars.

**Cost of conversion is assumed negligible. The assumptions which lead to the large LCC difference between conversions and new boilers may not be fully realistic.

***Congress does not permit new gas/oil boilers of this size. They are included here for comparison.

Table 97

Alternatives to 80 MBtu/Hr Gas/Oil Boiler (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Gas	Packaged gas/oil watertube (21)	0.0	15.4
Resid	Packaged gas/oil watertube (21)	0.0	15.7
	Conversion or Retrofit**		
CWM	Coal-water mix retrofit (39)	4.0	15.3
COM	Coal-oil mix retrofit (37)	2.5	16.1
Coal-hi	Coal reconversion with baghouse (32)	4.9	18.3
CWM	Coal water retrofit with scrubber (40)	5.7	19.5
Coal-mid	Coal reconversion with scrubber (33)	6.4	20.2
Coal-lo	Coal low-Btu gasification (27)	6.3	25.1
Wood	Wood low-Btu gasification (30)	7.5	28.6
Waste***	Waste low-Btu gasification (31)	11.8	31.8
	New Boiler(s)		
Gas+	Packaged gas/oil watertube (21)	1.6	16.1
Resid+	Packaged gas/oil watertube (21)	1.6	16.4
Waste***	Heat-recovery incinerator (18) (two)	8.4	18.5
Coal-mid	Pulverized coal with baghouse (3)	10.5	20.8
Coal-hi	Field-erected stoker with baghouse (1)	9.3	21.4
Wood	Field-erected wood stoker (6)	11.4	22.1
Coal-mid	Field-erected stoker with scrubber (2)	10.9	23.0

*Existing packaged gas/oil watertube boiler, 80 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4. Gas/oil boilers this large are rare at Army installations. FC and LCC in millions of 1980 dollars.

**None of these conversions or retrofits are recommended for this CF.

***An Army installation does not generate enough waste to supply this large a requirement.

+Congress does not permit new gas/oil boilers of this size. They are included here for comparison.

Table 98

Alternatives to 80-MBtu/Hr Gas/Oil Boiler (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Gas	Packaged gas/oil watertube (21)	0.0	35.3
Resid	Packaged gas/oil watertube (21)	0.0	36.2
	Conversion or Retrofit**		
CWM	Coal-water mix retrofit (39)	4.0	[illegible]
Coal-mid	Coal reconversion with scrubber (33)	6.4	31.4
Coal-hi	Coal reconversion with baghouse (32)	4.9	32.6
CWM	Coal water retrofit with scrubber (40)	5.7	[illegible]
Waste***	Waste low-Btu gasification (31)	11.8	33.2
COM	Coal-oil mix retrofit (37)	2.5	35.0
Coal-lo	Coal low-Btu gasification (27)	6.3	35.1
Wood	Wood low-Btu gasification (30)	7.5	43.3
	New Boiler(s)		
Coal-lo	Pulverized coal with scrubber (4)	11.9	30.5
Waste***	Heat-recovery incinerator (18) (two)	8.4	30.7
Wood	Field-erected wood stoker (6)	11.4	32.3
Coal-mid	Field-erected stoker with scrubber (2)	10.9	34.1
Gas+	Packaged gas/oil watertube (21)	1.6	35.0
Resid+	Packaged gas/oil watertube (21)	1.6	35.9
Coal-hi	Field-erected stoker with baghouse (1)	9.3	35.7

*Existing packaged gas/oil watertube boiler, 80 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4. Gas/oil boilers this large are rare at Army installations. FC and LCC in millions of 1980 dollars.

**Among these conversions or retrofits, only the coal reconversions can be recommended at this time. Further development is required for the CWM/COM technologies.

***An Army installation does not generate enough waste to supply this large a requirement.

+Congress does not permit new gas/oil boilers of this size. They are included here for comparison.

Note that various but fairly high capital costs are associated with each conversion or retrofit alternative in Tables 97 and 98. Among retrofits, only a coal reconversion is recommended, and only if the energy use (CF) is high. That is, if this is a former coal boiler that has been converted to oil, a reconversion to coal is worthy of study. As before, the costs of coal-water technologies are speculative, but merit further study. Also, front-end gasification continues not to be a good choice for an 80 MBtu/hr size. A tune-up that improves efficiencies may effect a good savings for this large a boiler. Apart from the coal-water options, it is now at a size where a new solid-fuel boiler becomes cost-effective in terms of LCC. For example, a new field-erected pulverized coal (PC) boiler is competitive with the existing gas/oil boiler, and there are a number of other solid-fuel alternatives for new construction.

Tables 99 and 100 show alternatives to an existing 80 MBtu/hr coal boiler, and include some of the new solid fuels alternatives just mentioned. But the message here is "If you have one, keep it." Because the new boilers have a high first cost, and because the existing technology already uses solid fuels, a new boiler will increase LCC. Also, the retrofits to waste, DRDF, and wood are marginal. The best bet for a retrofit is to use a cheaper coal, where feasible. For the new boilers, there are a number of technologies for comparison at this size. Again, the AFBC technologies look competitive, and there are several of them. The pulverized coal technologies look better than stoker boilers because less expensive coals have been assigned to them. Other sources have suggested that 100 MBtu/hr output may be a lower limit for cost-effective use of PC technologies. Note also that multiple packaged coal boilers may cost more than a smaller number of field-erected ones. An exception here is where waste is the fuel, because a field-erected waste stoker boiler is high in first cost. Note, however, that this amount of waste would entail a cooperative venture with an adjoining city. An Army installation does not generate enough waste to supply this large a requirement.

Finally, Tables 101 and 102 show alternatives to an existing 160 MBtu/hr coal boiler, and demonstrate the opportunity for savings through not buying a new replacement. High first-cost coal boilers should be retained, because a replacement will have a higher LCC. Where feasible, a less expensive fuel should be used. This is true for CF = 0.6, even if it requires the addition of a scrubber. In cases where a new boiler of this size is needed, pulverized coal is the better technology (vs. stoker boilers). The congressional requirement for solid fuels is seen to be reasonable for this size unit, when it is used fully.

Table 99

Alternatives to 80-MBtu/Hr Coal Boiler (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Coal-lo	Field-erected stoker with baghouse (1)	0.0	9.2
Coal-mid	Field-erected stoker with baghouse (1)	0.0	10.9
Coal-hi	Field-erected stoker with baghouse (1)	0.0	13.1
	Conversion or Retrofit		
Wood	Coal to wood retrofit (34)	0.8	19.0
DRDF	Coal to DRDF retrofit (35)	2.9	22.4
Waste**	Coal to waste retrofit (36)	6.7	23.1
	New Boiler(s)		
Gas***	Packaged gas/oil watertube (21)	1.6	16.1
Resid***	Packaged gas/oil watertube (21)	1.6	16.4
Waste**	Heat-recovery incinerator (18) (two)	8.4	18.5
Coal-lo	Coal circulating AFBC (23)	10.2	20.5
Coal-mid	Pulverized coal with baghouse (3)	10.5	20.8
Coal-lo	Field-erected AFBC with baghouse (5)	11.0	20.9
Coal-hi	Field-erected stoker with baghouse (1)	9.3	21.4
Wood	Field-erected wood stoker (6)	11.4	22.1
Wood	Wood circulating fluid bed (24)	11.0	22.5
Coal-lo	Pulverized coal with scrubber (4)	11.9	22.8
Coal-mid	Field-erected stoker with scrubber (2)	10.9	23.0
Coal-mid	Packaged coal AFBC (14) (two)	6.3	24.6
Wood	Packaged wood stoker (11) (two)	7.1	24.9
Waste**	Packaged waste stoker (12)	13.5	34.7

*Existing field-erected stoker boiler with baghouse, 80 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4. FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**An Army installation does not generate enough waste to supply this large a requirement.

***Congress does not permit new gas- or oil-fueled boilers of this size. They are included here for comparison.

Table 100

Alternatives to 80-MBtu/Hr Coal Boiler (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Coal-lo	Field-erected stoker with baghouse (1)	0.0	16.5
Coal-mid	Field-erected stoker with baghouse (1)	0.0	21.5
Coal-hi	Field-erected stoker with baghouse (1)	0.0	28.1
	Conversion or Retrofit		
Waste**	Coal to waste retrofit (36)	6.7	24.4
Wood	Coal to wood retrofit (34)	0.8	31.1
DRDF	Coal to DRDF retrofit (35)	2.9	33.6
	New Boiler(s)		
Coal-lo	Coal circulating AFBC (23)	10.2	28.3
Coal-lo	Field-erected AFBC with baghouse (5)	11.0	28.6
Coal-lo	Pulverized coal with scrubber (4)	11.9	30.5
Coal-mid	Pulverized coal with baghouse (3)	10.5	30.5
Waste**	Heat recovery incinerator (18) (two)	8.4	30.7
Wood	Field-erected wood stoker (6)	11.4	32.3
Wood	Wood circulating fluid bed (24)	11.0	33.1
Coal-mid	Field-erected stoker with scrubber (2)	10.9	34.1
Gas***	Packaged gas/oil watertube (21)	1.6	35.0
Resid***	Packaged gas/oil watertube (21)	1.6	35.9
Coal-hi	Field-erected stoker with baghouse (1)	9.3	35.7
Coal-mid	Packaged coal AFBC (14) (two)	6.3	36.4
Waste**	Packaged waste stoker (12)	13.5	36.5
Wood	Packaged wood stoker (11) (two)	7.1	36.5

*Existing field-erected stoker boiler with baghouse, 80 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4. FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**An Army installation does not generate enough waste to supply this large a requirement.

***Congress does not permit new gas- or oil-fueled boilers of this size. They are included here for comparison.

Table 101

Alternatives to Existing 160-MBtu/Hr Coal Boiler (CF = 0.2*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Coal-lo	Pulverized coal with baghouse (3)	0.0	16.4
Coal-mid	Pulverized coal with baghouse (3)	0.0	19.6
Coal-hi	Pulverized coal with baghouse (3)	0.0	23.8
	New Boiler		
Gas**	Field-erected gas/oil (19)	6.6	29.2
Resid**	Field-erected gas/oil (19)	6.6	29.8
Coal-mid	Pulverized coal with baghouse (3)	16.0	34.0
Coal-hi	Field-erected stoker with baghouse (1)	14.1	35.9
Coal-lo	Pulverized coal with scrubber (4)	18.3	36.7
Coal-mid	Field-erected stoker with scrubber (2)	16.6	37.7

*Existing pulverized coal boiler with baghouse, 160 MBtu/hr output capacity, 0.2 annual capacity factor, DOE Region 4. Coal boilers of this size (and larger) are found at several Army installations. FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**Congress does not permit new gas/oil boilers this large. They are included here for comparison.

Table 102

Alternatives to Existing 160-MBtu/Hr Coal Boiler (CF = 0.6*)

Fuel	Technology	FC	LCC
	Continue Current Process		
Coal-lo	Pulverized coal with baghouse (3)	0.0	30.5
Coal-mid	Pulverized coal with baghouse (3)	0.0	40.0
Coal-hi	Pulverized coal with baghouse (3)	0.0	52.6
	Conversion or Retrofit		
Coal-lo	Convert from coal-hi and add scrubber	2.5	35.3
Coal-mid	Convert from coal-hi and add scrubber	2.5	45.0
	New Boiler		
Coal-lo	Pulverized coal with scrubber (4)	18.3	52.0
Coal-mid	Pulverized coal with baghouse (3)	16.0	53.4
Coal-mid	Field-erected stoker with scrubber (2)	16.6	60.0
Coal-hi	Field-erected stoker with baghouse (1)	14.1	64.5
Gas**	Field-erected gas/oil (19)	6.6	65.4
Resid**	Field-erected gas/oil (19)	6.6	67.2

*Existing pulverized coal boiler with baghouse, 160 MBtu/hr output capacity, 0.6 annual capacity factor, DOE Region 4. Coal boilers of this size (and larger) are found at several Army installations. FC and LCC in millions of 1980 dollars. "Coal-lo," "coal-mid," and "coal-hi" indicate three prices for coal.

**Congress does not permit new gas/oil boilers this large. They are included here for comparison.

8 SUMMARY AND RECOMMENDATIONS

AR 420-49 is the principal policy document for guidance in fuel selection. Moreover, for guidance in fuel selection on a site-specific basis, ETL 1110-3-332 must be followed. It is essential that current policy be determined, both for fuel price calculations and for LCC analysis procedures, in developing an actual project.*

The major goal of this report has been to provide background data for future revisions of Army documents pertaining to facilities fuels selection. Results of this study are based on regional forecasts of fuels price and availability and on LCC analyses employing a variety of combustion technologies. The fuels ranking results are relatively insensitive to the assumptions used in this study. The analysis and results, as based on the assumptions concerning future technology costs and fuel prices, indicate a number of trends. Fuels selection recommendations follow, based on these trends. They are gr uped as general selection criteria, and as criteria for solid fuels, gas/oil fuels, and electricity.

General Criteria

For new construction, the fuel selected, as well as the design of heating units or plants, should be based on an economic study of the life-cycle costs of the technology alternatives and heating requirements to be served, using a 25-year analysis period. For units or plants of more than 20 million Btu/hr (MBtu/hr) output, the fuel, operation, and maintenance costs should be based on an annual capacity use of 60 percent over the 25-year analysis period. (The annual capacity use represents the annual energy output as a fraction of the potential annual output.)

As new or developing technologies become available and nearly competitive economically, consideration should be given to establishing Army demonstration projects for these technologies. Examples of such technologies are fluidized-bed combustion of solid fuels and high-efficiency furnaces.

There may be cases where it is cost-effective for a plant to use several primary fuels (e.g., there might be base-loaded coal boilers and gas/oil boilers for swing or peak loads).

Criteria for Coal and Other Solid Fuels

Solid fuels include solid fossil fuels such as coal, biomass fuels such as wood, and solid waste fuels. Coal is the most important of these because of favorable forecasts of coal prices and availability. Solid waste fuels include refuse, refuse-derived fuel, and densified refuse-derived fuel.

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*OCE letter (DAEN-ECE-G and DAEN-ECE-E), 30 December 1985, Subject: Economic Studies for MCP Designs; B. C. Lippiatt, et al., *Energy Prices and Discount Factors for Life-Cycle Cost Analysis*, NBSIR 85-3273 (Annual Supplement to NBS Handbook 135: the above OCE letter states this to be an update of Appendices A, B, and C of 10 CFR 436A.), (National Bureau of Standards, 1985); Revisions of 10 CFR 436 (Code of Federal Regulations, 1985); *Revisions of DOE/CE-0101* (Department of Energy, September 1984); *Engineering and Design -- Economic Studies*, ETL 1110-3-332 (Department of the Army, 22 March 1982); AR 420-49.

New units or plants of 100 MBtu/hr output or more should generally have coal as the primary fuel. Both conventional and fluidized-bed technologies may be considered and compared for technical and economic feasibility. All units or plants constructed to burn solid fuel should include those auxiliaries necessary to meet air pollution criteria.

Where technically and economically feasible, the use of combustion technologies that burn waste or biomass may be considered in the design of new facilities.

Criteria for Gas/Oil Fuels

New single-fuel gas or oil units or plants of 20 MBtu/hr output or more should be discouraged. Where new units or plants of 20 MBtu/hr output or above are being designed for oil or gas, dual-fuel gas/oil units capable of operation on both gas and oil, if both are available, should be considered. Dual-fuel burners are marketed that use both natural gas and distillate oil. Alternatively, it may be economically better to use separate replacement burner systems for natural gas and for residual oil.

Existing single-fuel oil-burning units or plants of more than 20 MBtu/hr output should be provided with the dual-fuel capability of also burning natural gas, where available, to provide increased flexibility in response to fluctuations in the prices and availability of either fuel.

Existing single-fuel natural gas units or plants of more than 20 MBtu/hr output should be modified to provide dual-fuel capability, where feasible, to provide increased flexibility in response to fluctuations in fuel prices and availabilities. Possible alternative fuels include residual oil and coal-slurry fuels.

New oil-fired units might be permitted to use distillate fuel oil (No. 2) for sizes up to 5 MBtu/hr output capacity. Those of 20 MBtu/hr output capacity or more should be able to burn a variety of grades of heavier oil, No. 4 through No. 6.

Existing distillate oil units or plants of more than 5 MBtu/hr output should be modified to reduce use of this fuel. Distillate may be used in units where the annual capacity use is less than 20 percent, because of the difficulties involved in storing and burning No. 6 oil.

Criteria for Electricity

The use of electrical resistance heating of large units or plants is generally not recommended.

Electrical resistance heating of smaller units or plants should be considered only where economically justified in comparison with other energy technologies, and where permitted by current policy guidance.

METRIC CONVERSIONS

1 mile	= 1.6 km
1 ft	= 0.305 m
1 lb	= 0.454 kg
1 Btu/hr	= 0.293 W
1 Btu	= 1055 J
1 cu ft	= 0.0283 m^3
1 lb/sq in.	= 6895 Pa
1 gal (U.S. Liquid)	= $3.78 \times 10^{-3} m^3$
(^oF-32)/1.8	= ^oC
k	= kilo (1 thousand)
M	= mega (1 million)

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